POWER AND WATER AUTHORITY
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PRINCIPLES FOR ESTABLISHING NETWORK PRICES

PAWA SUBMISSION TO THE INTERIM OFFICE OF THE UTILITIES COMMISSION

13 MARCH, 2000

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1. INTRODUCTION

This Submission to the Office of the Interim Utilities Commissioner presents PAWA's views regarding appropriate pricing principles, and details of PAWA's proposed approach for establishing network reference tariffs.

PAWA's approach focuses on the objectives of ensuring that consumption and investment signals are efficient, whilst balancing the need to produce a tariff schedule that is equitable and administratively practical.

The proposed tariff schedule takes into consideration the size and structure of the Darwin and Katherine energy markets. The size of the total load is only 1100 MWh, and the Darwin and Katherine networks (ie the two main networks) are relatively compact. Hence it is not considered necessary nor appropriate to separate transmission and distribution prices within these networks given the relatively small and interconnected nature of the networks.

Broad geographic differentiation is included in the tariff in order to retain a reasonable degree of consistency between tariffs and associated network costs. Moreover, the tariffs reflect the lesser dependence by large users on the low voltage network infrastructure, the lower cost of providing service during off-peak periods, and the high proportion of fixed costs in total costs.

In essence, the costs of owning and operating each network will be recovered from users on a Fully Distributed Cost (FDC) basis, with contributions from each customer commensurate with the quantity and value of assets required to deliver the service to them.

It is proposed that the structured network price approach outlined in this Submission will only be applied to contestable customers for at least the first full regulatory period to 2003. During this period, Franchise customers will be allocated the balance of the revenue cap, and this network charge will be recovered as a cents per kWh charge. It is PAWA's intention that as more tranches become contestable, the complete three-part tariff for network services — forwarded in this Submission — will be utilised for these tranches. The three-part tariff consists of —

1) demand related charge ($ per kVA) including time of use (TOU) rates;
2) charge related to energy (cents per kWh) including time of use rates; and
3) a fixed "service availability" charge ($ per day).

Section 2 of this Submission describes the three tariff schedules currently in use — two general tariffs (largely energy based) and the standard demand tariff — all of which are total ("bundled") electricity tariffs. Section 2 also highlights the degree of cost reflectiveness and demand management in the standard demand tariff (the proposed network tariff follows the same price structure principles evident in this tariff). The effects of the new regulatory regime on the total electricity bill for non-contestable customers (e.g the effect of the proposed cost allocation method), is also considered in Section 2.

Section 3 examines the proposed network tariff schedule — the schedule will apply to contestable customers only. PAWA's proposed cost allocation methodology is also discussed in Section 3 — this will have a direct impact on the tariffs of both franchise and contestable customers. Section 4 assesses PAWA's proposed network tariff schedule against the widely accepted pricing criteria. Finally, issues relating to excess network usage charges are examined in Section 5.

2. CURRENT BUNDLED TARIFFS

PAWA currently utilises three separate tariff schedules — the domestic tariff for residential customers; the general purpose tariff for commercial or industrial customers; and choice of a standard demand tariff for larger commercial and industrial customers. The tariff schedules are "bundled" prices which include generation, retail and networks and it is not possible to isolate exactly the proportion of the tariff that is attributable to networks. The general tariff schedules are shown in Table 1 and the standard-demand tariff schedule is shown in Table 2.

Under each of these tariff schedules there is a flat rate cents per kWh charge, and an optional time of use tariff, although the time of use option is rarely taken up by domestic customers. In addition, there is a relatively low daily fixed charge.

TABLE 1: GAZETTED ELECTRICITY TARIFFS[a]

	Fixed daily rate (¢/day)	**Energy rate (¢/kWh)**	**Peak energy rate (¢/kWh)**	**Off peak energy rate (¢/kWh)**
		(Anytime)	(Time of Use Options)	
Domestic standard tariff	25.41	12.9	12.9	10.8
General purpose tariff	39.69	15.5	21.0	10.8
NT Government tariff	41.51	17.0	21.0	10.8
Prepayment Meter tariff	0	16.0	na	na

a) Effective from 1 April 1999.

Under the "standard demand" tariff that has been in place since 1 April 1999, the following three elements are utilised —

- a demand charge (maximum kVA per period);
- a charge related to energy usage (kWh per period); and
- a fixed charge ($ per day).

Declining block rates, and time-of-use charges, are incorporated in both the demand charge and the energy component of the standard demand tariff.

To utilise the standard demand tariff shown in Table 2, PAWA needs to install sophisticated, and more costly, metering devices. The system availability charge of $3.20 per day is to partly recover the cost of detailed metering that records the active and reactive energy consumed during every fifteen minute period, as this information is used when calculating the charges arising out of the demand tariff.

TABLE 2: STANDARD DEMAND TARIFF[ab]

	Peak[c] (¢ / kWh)	Off Peak (¢/kWh)		Peak $/kVA[d]	Off Peak $/kVA
Energy Tariff Element			(plus) Demand Tariff Element		
First 10,000 kWh	10.30	9.30	First 50 kVA	23.00	3.00
Next 20,000 kWh	10.20	9.20	Next 100 kVA	21.00	2.75
Next 50,000 kWh	10.10	9.10	Next 300 kVA	19.00	2.50
Next 100,000 kWh	10.00	9.00	Next 500 kVA	17.00	2.25
Next 200,000 kWh	9.90	8.90	Next 1000 kVA	15.00	2.10
Next 200,000 kWh	9.80	8.80	Next 1000 kVA	14.00	2.00
Balance of monthly energy consumption	9.70	8.70	Balance of monthly demand	14.00	2.00

a) from 1 April 1999.
b) in addition there is a system availability charge of $3.20 per day.
c) peak is 6.00 am to 6.00 pm all days.
d) kVA is kilo-volt ampere — which is a measure of the capacity required, or peak demand during each period (the charge is levied against the peak kVA reading recorded during each month).

Consumers who consume more than 160 MWh per annum can elect to choose whichever is the more advantageous of the standard demand or the general tariffs. The standard demand option is attractive to customers able to interpret its impact and which expect to benefit from its load management incentives. Hence, the standard demand tariff has generally only been taken up by larger customers. It provides incentives for users to improve load factors by reducing peaks and spreading energy use over a wider time frame, and to improve power factor (if power factor improves then less kVA is required to supply a given level of energy (kWh)). An example of how customers can improve power factor is through the installation of capacitors. One customer has significantly improved its load factor by the installation of chilled water storage, which is replenished overnight at off peak rates.

The standard demand tariff is both cost reflective and promotes demand management, as —

- The *demand charge* is based on peak measured kVA in a month. This reflects the fact that the network and generation costs are dominated by fixed rather than variable costs, and that the level of infrastructure required is determined by the capacity required to meet peak demand. Structuring the demand charge this way means that the average charge per kWh will be lower for customers making more effective use of the infrastructure by more evenly spreading their energy use over time (i.e. customers with a high load factor (total energy use/total energy use if peak rate continued uniformly over the entire month)).[1]

- The lesser dependence by large users on the low voltage network infrastructure is the reason for the unit demand charge falling as kVA increases. i.e. the demand tariff declines across the increasing brackets.

[1] It should be noted that while large users with high load factors would be better off under the standard demand tariff than under the general tariff, some users unable to achieve a high load factor may pay less under the general tariff. This is essentially because an “average” load profile is assumed under the general tariff.

- The demand tariff is based on kVA rather than kW, and hence better pricing signals are given to users, as their total charges will be lower if they improve the power factor associated with their usage.

- Time of use tariffs currently differentiate between peak (6am to 6pm) and off peak consumption (6pm to 6am), however the standard demand tariff differentiates between peak and non-peak to a much greater extent than the general electricity tariff. Since the demand tariff has been introduced there has been some significant improvement in load profiles of some of the large customers.

- *Energy charges* mainly recover generation and retail costs, although a small component of the energy charge relates to network costs and this works to moderate the demand signals to an extent.

2.1 THE PROPOSED THREE-PART NETWORK TARIFF WILL ONLY APPLY TO CONTESTABLE CUSTOMERS

It is important to note that while PAWA anticipates introducing a network demand tariff it does not anticipate making this tariff applicable to non-contestable customers (i.e. customers using < 750 MWh). Small customers (i.e. customers using < 160 MWh) are currently supplied under the commercial or domestic tariffs, and this will continue to be the case unless the NT Government determines otherwise. Customers using between 160 MWh and 750 MWh will have the option of the general and demand total electricity tariffs, but the network tariff will not be identified specifically to them in the “bundled” tariff.

It is not envisaged that the benefits in terms of load profile smoothing and improving power factor, that are to be realised from large customers through the introduction of the demand tariff, would be realised to the same extent if the tariff was available to smaller customers. It is not realistic, for example, to expect domestic users to substantially improve their load factors. Moreover, the cost of sophisticated metering equipment may outweigh any cost saving to the user in which case it would be inefficient to introduce a demand tariff for franchise customers. The proposed network tariff also requires the measurement of the same parameters as the demand tariff (kVA, kWh) and the simple meter provided for customers who will remain franchise customers does not record demand levels and profiles.

Hence, bundled electricity tariffs will continue to apply for most customers and the retailer to contestable customers may continur to offer a bundled tariff. The main changes for franchise customers are that the embedded network charges will be differentiated across broad geographic regions, and under the proposed cost allocation method franchise customers may be allocated a more equitable and larger share of common costs than currently occurs. However, the Minister sets the franchise tariffs and therefore there is uncertainty as to whether geographic differences in network costs, and franchise customers’ greater allocation of common costs, will be reflected in the tariff set in this manner. The franchise tariffs will retain the structure of the existing gazetted tariffs.

3. PROPOSED NETWORK TARIFF SCHEDULE

It is proposed that the three main cost signalling elements of the current standard demand tariff be retained in the network tariff for contestable customers — i.e. the demand charge, a charge based on energy, and a fixed charge per period. In addition it is proposed that charges will continue to vary across peak and non-peak periods, and that declining scale demand and energy charges will be applied in reflection of the lesser dependence of large users on the low voltage network infrastructure.

For both franchise tariffs and contestable tariffs, it is proposed that (over time and as data is gathered) different tariffs should apply to Darwin, Outer Darwin, Katherine and Outer Katherine. It is not considered appropriate to provide separate tariffs for locations within the above-mentioned areas, because the improved pricing signals are likely to be minor in comparison to the added administrative cost and equity concerns.

Fully Distributed Costs (FDC) is PAWA’s preferred pricing methodology. This results in revenue from each customer commensurate with the quantity and value of assets required to deliver the service to them.

There are three broad steps in determining the schedule of tariffs. *First*, costs (i.e. the total revenue cap) are allocated to each of the three main cost categories and to each of the geographic locations. *Second*, to achieve cost reflectivity, demand management and other pricing objectives, costs need to be converted into demand charges, charges relating to energy use, and fixed charges. *Third*, peak/off peak and declining block rates need to be established.

3.1 ALLOCATION OF COSTS

The proposed method of relating the cost drivers to tariffs for each tariff grouping, is to firstly separate costs into the following three categories —

- common service costs — costs which relate to the provision of assets to provide service to the overall system and any non-asset related costs which may not be appropriate to allocate to individual parts of the system;
- connection assets — the cost of providing assets which are dedicated to the supply of a customer or group of customers connected at a single point within the network; and
- distribution use of system or “network carriage” assets — these are shared to a greater or lesser extent by all users across the system.

The main asset items and cost items that need to be allocated across the three categories are — 132 kV and 66 kV lines; zone substations; 11 kV lines; distribution sub-stations; low voltage mains; customer services; metering; system control; and the contracted use costs for the Darwin to Katherine Transmission Line (DKTL).

Common Services include "network operation" (a component of total system control) and the DKTL, although the DKTL costs receive special treatment to reflect specific costs and use of the line.

Connections include "customer services" and metering as well as some element of substation and mains costs. These costs are directly related to individual customers and tariffs should therefore reflect their direct cost.

Network Carriage assets include the 132 kV, 66 kV, 22 kV and 11 kV lines, and the low voltage mains. Those elements of the zone substations and distribution substations that provide the energy transfer facility are included in the *Network Carriage* category.

Two types of indirect costs need to be attributed and allocated into the above cost categories — "overhead" costs and indirect service unit costs (service units include accounting, corporate, etc).

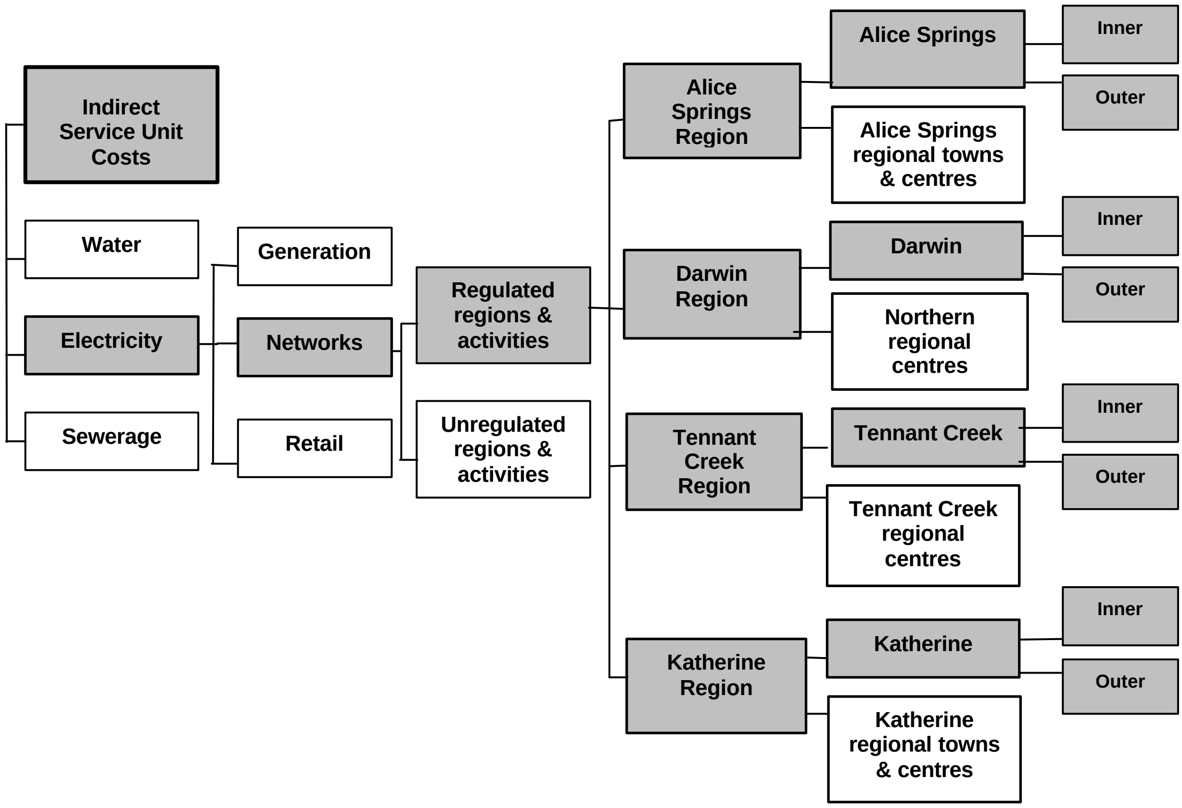
Overhead costs consist of costs related to motor vehicles, construction equipment, computers, office equipment, software, operations and management of the business, general overheads and other expenses that cannot be directly identified across common services, connection assets or distribution use of system service.

3.1.1 Indirect service unit costs

Indirect service unit costs should firstly be allocated between water, sewerage, electricity generation, electricity retail, electricity networks, system control and rural services (Aboriginal Communities). *Second*, the amount allocated to networks must be allocated between capex and operations maintenance & administration (including repairs). Further, any costs (including overheads) attributed to non-regulated activities need to be deducted. Next, the costs need to be allocated across geographic regions. At this point the network's share of indirect service unit costs will be incorporated into the above three cost categories.

The different strata across which indirect service unit costs must be allocated are shown in Figure 1 below.

FIGURE 1: ALLOCATION OF INDIRECT SERVICE UNIT COSTS



3.1.2 System control costs

Traditional system control can be divided into a) services provided to the hydraulic activities (water, sewerage); and b) electricity system control. There are two parts of electricity system control: a) the network switching function; and b) the electricity market management function.

The traditional system control function is allocated between water, electricity, and sewerage according to assessed levels of activities on these services (e.g. it only deals with water and sewerage emergency calls out of hours, whereas all electricity operations are coordinated at this centre 24 hours per day).

The network switching function is included in the revenue cap and the market management functions for generators and retailers are outside the revenue cap. The network switching function is a component of operations and maintenance. The market management function will be recovered on a kWh (i.e. “postage stamp”) basis.

PAWA’s preference is to make this final allocation of system control costs according to energy because this is considered to be the most equitable way of allocating what is essentially a common cost

3.1.3 The Darwin to Katherine Transmission line (DKTL)

For the DKTL, PAWA intends to relate the charge to the contractual reservation of line capacity in kW or kVA. PAWA considers this provides a close link between prices and the cost of building capacity to meet generators' requirements. The rationale behind this allocation methodology is two fold—

- potential users of the DKTL will nominate realistic values at the exit connection points, thus not providing false augmentation signals; and

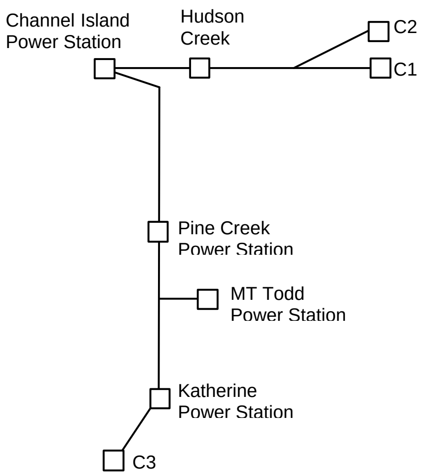
- any generator which chooses to locate along the line or remote from its customer, contributes an equitable proportion to the cost of ownership, operation and management of the line. There is a strong locational signal in this methodology.

Presently, the charges on the DKTL are approximately $5 million per annum and the contractual arrangements are largely based on energy transfers. PAWA's capacity reservation in the line would be some 45-50 MVA (by summing off-takes at all points). Whilst PAWA Generation is the only party[2] which has "contracted" or "nominated" off-take capacities, PAWA Generation will pay 100 per cent of the charges. As other parties nominate off take quantities PAWA would pay proportionately less than the 100 per cent with the other parties bearing charges in proportion to their nominated off take.

It is constructive to examine the following diagram of the DKTL before considering the main issues in relation to examination of energy and load flows.

[2] In fact, NTPG is connected to the line and PAWA has sale arrangements with NTPG which will add any off take by PAWA at this point to the equation as well.

FIGURE 2: DARWIN TO KATHERINE TRANSMISSION LINE



It can be seen from the above diagram that energy flows from Channel Island Power Station (CIPS) to customers in Darwin and outer Darwin (C1 and C2) may not directly utilise the DKTL. If the energy is sold by PAWA Generation however some energy from the independent power producer at Pine Creek or from PAWA's Katherine power station may be used to satisfy some of the customer demand.

In contrast, a sale from the Mt Todd Power station to customers C1, C2 or C3 will rely on the DKTL, and consequently the total network charge will be higher for energy flows originating from Mt Todd. Complicating this, however, is that if energy is being transported from CIPS to Katherine, simultaneous to energy being sold contractually from Mt Todd to, say, C2 then, depending on the load magnitudes, physically the energy flow may be from CIPS to C2 and from Mt Todd to C3. Therefore the actual energy flow may not always simply be equal to the contracted off-take nominated by the generator/retailer. This actual energy flow complication is ignored in the proposed allocation of DKTL costs on the basis that if the other generator's loads did not exist, the flow of energy would be consistent with nominated capacity at off-take points.

As there are system-wide benefits to PAWA Generation and its connected customers associated with use of the DKTL line, once its proportion of the $5 million (approx.) cost has been allocated to PAWA, it is proposed that this cost be distributed across all its (PAWA's) customers on an energy (kWh) basis. The PAWA share should not be allocated across all network users but, rather, it should only be allocated across energy used by customers of PAWA Generation. Otherwise, customers supplied by competing generators would be charged twice for the DKTL.

3.1.4 Allocation of connection costs

Connection Costs should be identified for each of the 4 sub regions — inner and outer Darwin, and inner and outer Katherine. Ideally, in so far as they are fixed costs, they should be recovered as a fixed charge per day in network tariffs. While part of the connection cost is recovered through the fixed charge per day, part of the cost is recovered through the demand charge and the charge on energy, simply because high fixed (standing) charges, are not acceptable to all consumers, particularly low energy

3.1.5 Allocation of network carriage costs

can be allocated directly to each region.

Within each region, costs are to be allocated between 1) transmission, zone substation

The relevant cost at each supply point level would be allocated pro-rata with energy as shown in Table 3 below.

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Network Level	Cost[a]	Energy take-off	Energy pass-through	Allocation of C1	Allocation of C2	Total cost
Transmission Zone Substation & High Voltage Mains	C1	E1	E2	C1* E1/(E1+E2)	na	C1*E1/(E1+E2)
Distribution substation Low voltage mains	C2	E2		C1*E2/(E1+E2)	C2	C1*E2/(E1+E2)+ C2

a) It is proposed that the revenue cap be allocated to C1 and C2 on a pro rata basis according to the extent and value of assets used to supply customers at each level.

After the above final cost allocation has been conducted the costs for each geographic region/system tier grouping will be translated into a component of the final network tariff. PAWA considers this should be done by applying a demand charge and an energy charge.

The demand charge is most relevant from an economic efficiency point of view because the capacity requirements for the system are mainly determined by peak loads. However, despite network carriage costs being mainly fixed, it is generally not considered appropriate to recover all of its cost through the demand charge (see Section 4.4.2).

3.1.6 Summary of methodology for determining charges

The proposed approaches for converting the final allocations of costs into components of the network tariff are summarised in the following table.

TABLE 4: USE OF COST DRIVERS TO DETERMINE CHARGES

Cost Element	Cost Driver	Allocation Method
System control costs	Energy flow; peak demand	Cents/kWh (100 %)
Connection costs	Number of customers; size of connection	$/day (50-70%) cents/kWh (15-30%) $/kVA (10-30%)
Network carriage	Peak demand	cents/kWh (40-60%) $/kVA (40-60%)

3.2 PEAK AND OFF PEAK CHARGES & DECLINING BLOCK RATES

The above methodology is sufficient to establish the *average* charges that should apply for each region and the two system tiers in order to recover system control; connection; and network carriage costs. It will also be appropriate, however, to accommodate time of use variations and declining block rates.

It could be argued that the long run marginal cost (LRMC) of low peak usage is extremely low because capacity is already in place. However, Burgess (1999) shows that it can be appropriate to recover part of the capital cost from off peak usage, although a smaller charge is appropriate. His argument is that peak and off peak supply are essentially different services that are “joint” outputs from a single production process. In this case the relativity between contribution to fixed (capacity related) assets should be dictated by the relative value of demand.

Burgess presents market-testing methods for determining the relativity between peak and off-peak demand and therefore for allocating fixed costs between peak and off peak usage. However, PAWA considers that it will be more appropriate to determine the split between off-peak and peak contribution to total costs on the basis of its perception of the responsiveness of customers to lower off-peak prices given previous changes in demand patterns after adjustments in the off-peak tariff. This approach is preferred given the difficulties and uncertainties associated with the market-testing approach. (In fact, PAWA’s experience over the next few years could give impetus to change, and is therefore a form of market testing).

Block rates are determined such that sample calculations are consistent with larger users’ “typical” lesser reliance on certain system assets, as they are upstream of low voltage connections.

3.3 POSSIBILITY OF PRICE FLUCTUATIONS WHEN MOVING TO NEW REGULATORY REGIME

One of the effects of moving to a new pricing regime is that there will initially be some fluctuation in prices. There are five principal reasons why this may eventuate.

Firstly, franchise customers will be required to contribute an equitable share of network costs. For franchise customers, networks will not charge customers directly, but instead will recover the network charge from PAWA Retail. As the Minister sets the franchise electricity tariffs, there may be opportunity to insulate small consumers from any cost increase resulting from the equitable recovery of network costs at the expense of cost recovery or profit in generation or retail activities.

Secondly, introducing differentiation of tariffs across regions will cause some prices to rise and others to fall. Again, for franchise customers the Government may or may not decide to allow the electricity tariffs to reflect the differences across regions.

Thirdly, any movement of contestable customers from flat-rate general tariffs to contract tariffs, where price signals are more pronounced, will contribute to price fluctuations during the implementation period. This is because if contestable customers choose to move to contract tariffs, any price fluctuation is likely to be negative (i.e. welcomed by the customer), and therefore a larger share of the revenue cap will need to be recovered from franchise customers.

Fourthly, the cost allocation across system tiers will infer a higher network cost for residential customers and small commercial customers than is currently the case.

Fifthly, PAWA estimates that the rate of return to invested capital has been less than two per cent in recent years. As from 1 April 2000, however, the network tariffs, and the network component of total electricity tariffs, will be based on the revenue cap which includes a specific rate of return to capitalIt should also be mentioned that prices applying after 1 July 2000 will need to recover the GST (net of rebates of taxes paid on inputs). This will be additional to the revenue cap, and will contribute to the net price fluctuation experienced during the initial regulatory period.

Whether the price fluctuations resulting from the above factors are excessive is an issue that PAWA considers is most appropriately addressed by the Utilities Commissioner and the NT Government. PAWA will, however, assist by quantifying the extent of the price fluctuations, once a decision has been made regarding the pricing principles that should be applied.

3.4 UNDERS AND OVERS

It is clear that there is some uncertainty regarding actual levels of demand and how users will respond to various pricing signals. Hence while the construction of the tariff schedule will be consistent with the revenue cap, it does rely on PAWA’s best estimates of the relevant parameters (for example how consumers respond to incentives to improve load factors, and how they respond to lower off-peak prices).

To the extent that these projected parameters are not equal to the resulting parameters, there may be some under- or over- shooting of the revenue cap. Where this is related to demand or cost factors outside PAWA's control an adjustment to the revenue cap between regulatory resets is appropriate. Where this is due to actual responses to pricing signals differing from those anticipated by PAWA, there will need to be some carry forward facility so that neither PAWA nor consumers are penalised.

The retailer(s) for all contestable customers will be charged network rates from the date the customer becomes contestable. The formulation of the network tariff is such that there is a possibility of unders and overs from the contestable customers segment. There is little possibility of unders and overs from franchise customers as the contribution to network's revenue cap by PAWA retail for franchise customers will be set at the level of the revenue cap less the expected network revenue from contestable customers.

4. CONSISTENCY WITH PRICING OBJECTIVES

PAWA's objectives for network pricing that are also regularly cited elsewhere, include —

- Economic signals — there should be appropriate signalling to network users of their impact on the network capacity and other network costs;
- Revenue recovery — network prices need to recover adequate revenue to sustain a viable network business, i.e. prices need to be sufficient to recover the revenue cap.
- Simplicity — prices should be straightforward in application and readily understood by network users.
- Stability — prices should remain stable over time to permit customers to make informed investment decisions.
- Equity — prices should be perceived as equitable by network users. Generally, this means that prices reflect the utilisation of the existing network.
- Prices should be subsidy free. From an economic efficiency perspective, this requires that the price for a customer, or group of customers, be no less than the incremental cost of meeting their needs and no more than the stand alone cost of supply.

Clearly, in some instances trade-offs will need to be made between some of the above objectives. Hence the overall aim is to produce a tariff schedule that adequately reflects the above objectives while incorporating a reasonable balance between conflicting objectives.

The Interim Utilities Commissioner (2000) has provided the following tests for assessing network pricing principles against the objectives found in Chapter 7 of the *Third Party Access Code* —

1. Are the prices cross subsidy free?
2. Do the proposed prices reflect an acceptable cost of supply model?
3. Do the prices reflect future need for augmentation?
4. Does the structure of prices reflect marginal economic costs?
5. What is the impact on price stability?
6. What is the impact on the net financial position of the Government, including CSO payments?

4.1 ARE THE PRICES CROSS SUBSIDY FREE?

The Interim Utilities Commissioner (IUC) (IUC 2000) has proposed that the standard rule for identification of cross subsidies be applied, i.e. that prices fall between incremental and stand alone costs. PAWA does not consider it necessary to formally apply this test, as typically, for networks, incremental cost is very low and stand alone cost is very high (although it is recognised that stand alone costs relate to the stand alone costs for a customer or group of customers and are not the costs for the entire network). In Section 4.6.3 there is further discussion of the correct context for applying the cross subsidy rule.

4.2 DO THE PROPOSED PRICES REFLECT AN ACCEPTABLE COST OF SUPPLY MODEL?

Section 3 describes how costs are allocated across the three main cost categories — system control costs, connection costs, and “the network”. The reason for allocating costs to these three cost categories is because there is a clear difference in the way cost drivers affect these cost categories.

The cost drivers PAWA has linked to these costs were summarised in Table 4. PAWA considers that by basing the tariffs directly on these cost drivers it has, in effect, represented in tariffs an acceptable cost of supply model. Modelling costs in a more detailed fashion in PAWA’s view would be counter to objective (e) in Clause 74, Chapter 7 of the *Third Party Access Code* which states that “ prices should reflect a balancing of the quest for detail against the administrative costs of doing so which would be passed on to end-use customers.”

4.3 DO THE PRICES REFLECT FUTURE NEED FOR AUGMENTATION?

The most important connection between tariffs and investment costs is the fact that peak demand (kVA) has been selected as a principal charging mechanism. This will lead to pricing signals indicating to a large extent the effect that increasing consumption has on the need to augment capacity.

However, the allocation of the revenue cap described in Section 3 is an averaging approach i.e. costs are averaged within locations and classes and hence the allocation method could be described as a fully distributed cost (FDC) approach. The effect is that prices are not expected to rise as capacity utilisation increases, in fact they should decrease. This is because the cost of fixed cost assets will be spread over a greater measured demand (kVA) and energy throughput (kWh) as the number of customers increases. In respect of a similar issue of cost reflective network pricing (for transmission pricing) NECA (1999, p.46) commented that —

> *It (cost reflective network pricing) can lead to perverse pricing signals because it seeks to reflect total, rather than marginal, costs to customers.*

> *This means that CRNP takes no account of the level of spare capacity in the system in setting prices. Therefore, if the system is at full capacity, CRNP will produce a lower unit price compared to a situation where there is spare capacity. Such pricing signals are the opposite of those which one would expect to see in a competitive market.*

Whilst this argument has merit in relation to larger transmission networks which may require sporadic large injections of capital it is not appropriate in the NT context, where the system is mainly a distribution system with a relatively small amount of transmission infrastructure.

Moreover, due to the compact nature of the networks within Darwin and Katherine the investment in the networks is not as lumpy as it is in larger networks. PAWA anticipates expansion of the customer base within the existing network as opposed to increasing the area covered by the network. Generally, the system is augmented by a series of incremental expenditures rather than large intermittent expenditures. (Longer term, of course, as major new satellite townships are established there will need to be more substantive augmentation). Therefore, analysis of maintenance requirements and loads is considered sufficient for the purpose of planning new investment, and hence periods of excessive capacity utilisation are unlikely. The omission of (periodic) pricing signals for the purpose of resolving excessive capacity utilisation is therefore not likely to lead to any real effect on investment and consumption patterns.

It is also important to recognise that the corollary is where there are large fixed costs and excess capacity, prices should decline to induce use of capacity until capacity is constrained. This is consistent with economic principles for effective pricing of infrastructure.

FIGURE 3: OVERALL COST ALLOCATION METHOD

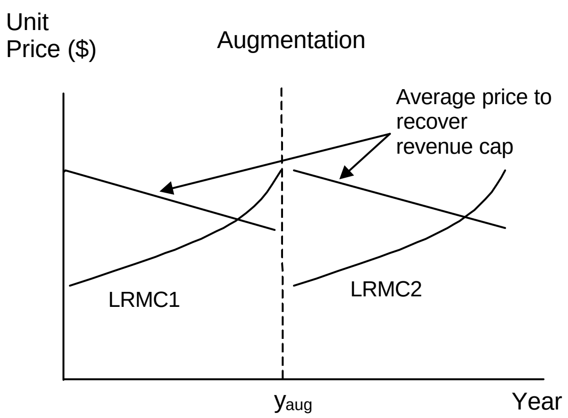

Figure 3 shows the difference between direct recovery of the revenue cap (including sunk costs) and LRMC pricing, by showing the impact on prices of a steady growth in load. Investment signals are provided under LRMC pricing. This is because it is forward looking, and costs increase as the date of augmentation approaches to reflect higher net present value of the augmentation cost which is attributable to the increment in demand.

In contrast, the average price to recover the revenue cap falls over time, because the capital costs are higher when the asset is newer, and the number of customers over which to spread total costs is relatively low. As capacity utilisation increases, prices fall because the asset is older and the number of customers increases.

In practice, the difference between the time profile of LRMC prices and the time profile of total revenue requirement may be less than indicated by the above “theoretical” diagram, as —

- most augmentations are relatively small;
- fluctuation in the LRMC of assets with different lives will be offsetting;
- the revenue cap will include capital works budgets that have been smoothed and this smoothing process may allocate some of the capital works cost to periods prior to augmentation. In practice, therefore, prices under the averaging approach may not fall by much prior to augmentation, because part of the cost of anticipated augmentation will be included in the tariff; and
- capital contributions are a significant component of charges for large users. The contributions are pure long run marginal costs as the user pays directly for attributable augmentation costs. Capital contributions fall outside the revenue cap, but continued use of capital contribution charges, as opposed to incorporation of such costs in demand and energy charges, will assist in mitigating any perverse pricing signals associated with adopting an averaging approach.

LRMC could by applied by using a variable pricing charge (cents per kWh or $ per kVA) for the LRMC component and a fixed charge to collect any revenue shortfall to cover long run total costs. However, as shown in Figure 3, this may involve considerable variation in the split between the fixed and variable pricing charge. This is not expected to be acceptable to consumers, and it is one of the reasons why PAWA prefers to structure prices by averaging network carriage costs across kVA and kWh. Due to its monitoring of load and the nature of the network, PAWA does not consider that this will have any perverse impacts on the timing of investment.

4.4 DOES THE STRUCTURE OF PRICES REFLECT MARGINAL ECONOMIC COSTS?

Marginal cost prices are often forwarded as being the most effective prices for transferring these signals. In contrast to marginal cost pricing, average cost pricing leads to a weak link between prices and resource use. Hence prices are often evaluated in terms of how closely they reflect marginal as opposed to average costs.

Marginal cost can be thought of in two ways —

- Short run marginal cost (SRMC) is the change in total costs associated with an incremental output change, where the capital stock is held constant (no new investment takes place). In the short run, the marginal cost of energy supply through a network is usually very small.

- LRMC is evaluated over a period, where future investment in the network is considered. Generally, the net present value of the cost of future network augmentation is considered and this cost is spread over the anticipated future increments in demand or energy. An important characteristic of the LRMC price is that it will be higher as the time of the next augmentation nears. This is because the PV of the cost of imminent augmentation will be higher than if the next augmentation were in the distant future.

Application of SRMC pricing for utilities infers that consumers would need to be charged a very large fixed cost if the utility is to break even. In contrast, LRMC prices have been estimated by EnergyAustralia to recover around 70-80 per cent of its total network costs (EnergyAustralia 1999), and although this estimated percentage does not directly relate to PAWA’s operations it does illustrate the extent of economies of scale for networks (it is only because economies of scale are still being realised that LRMCs do not recover total costs).

While not directly applying LRMC pricing, PAWA is comfortable with its use as a “conceptual” pricing principle. PAWA also recognises that SRMC pricing is the way prices are formed in competitive markets, and hence it is usually considered to be the “first best” pricing option. PAWA is therefore also comfortable with SRMC pricing being used as a conceptual pricing principle. (Note that in a long run equilibrium all costs are variable and hence SRMC=LRMC, but this notion is somewhat esoteric because markets are nearly always in transition).

It is recognised, however, that there are practical difficulties associated with directly applying either SRMC or LRMC pricing. For example, SRMC pricing incorporates congestion charging (rationing when capacity is very highly utilised is undertaken by incorporating in prices the value other consumers place on supply). PAWA does not consider congestion charges would be acceptable to customers and SRMC pricing may not be cost effective to implement. In addition PAWA does not think that it would be acceptable to users to apply a large lump sum or standing charge that would be required under SRMC pricing.

LRMC pricing would require very detailed estimates of load growth to determine how much each increment in demand actually contributes to costs. Moreover, a full LRMC approach would be difficult to calculate from the starting point of a revenue cap as LRMC pricing is a forward looking concept, which is in direct contrast to a revenue cap which presents investors with the opportunity to directly recover existing infrastructure costs. PAWA generally considers that future LRMCs should be proxied by existing sunk cost assets — this helps resolve some of the conflict between LRMC pricing and the need to recover the revenue cap.

Another concern in directly applying SRMC pricing, and to a lesser extent LRMC pricing, is that price volatility is likely to be higher than under PAWA’s proposed approach. This is considered to be unacceptable to consumers, particularly those making investment decisions, as they typically prefer a degree of certainty about future input costs.

In summary, PAWA proposes averaging costs over broad user groups as described in Section 3 and explicitly including sunk costs in charges. In these respects PAWA's proposed pricing methodology deviates from LRMC pricing. However, it could be said that PAWA's proposed tariff structure is inherently related to LRMC pricing in that peak demand has been selected as a principal charging mechanism, and therefore, there is a continuous pricing message about the cost of capacity. Charges based on other units encapsulate more averaging. In addition, it is not unreasonable to use sunk costs estimated with a depreciated optimised replacement cost methodology as a proxy for LRMC.

4.4.1 Recovery of fixed infrastructure costs and sunk costs

SRMC normally cannot be used to directly recover fixed costs (i.e. largely fixed infrastructure costs) nor sunk costs (utilisation of sunk costs confers a marginal cost for capital costs of zero). Moreover, LRMC pricing may not be able to recover all fixed costs (where average costs are higher than marginal costs) and as it is forward looking would not (directly) recover the sunk cost component of fixed costs. However, because LRMC recovers *future* incremental costs it would facilitate the recovery of a large component of sunk cost investment reflected in the *current* revenue cap.

To be consistent with efficient pricing, any shortfall in fixed costs, (including the sunk cost component) can be recovered using a Ramsey approach whereby relatively more costs are recovered from those consumers who are relatively less responsive to a price change. Such an approach would be consistent with the IUC's (IUC 2000) Criterion 4.4 for assessing network pricing —

> *Alternatively, prices may be designed to reflect sunk accounting costs. While such approaches may have little merit in terms of economic efficiency, they are consistent with the recovery of the overall revenue network cap. The economic task for pricing is therefore to cover the difference between economic costs and accounting costs in the least distorting manner possible.*

A Ramsey approach sends the correct pricing signals to customers in that it reduces the extent to which consumers' consumption decisions will be affected by the charging of prices above incremental costs. And it is this characteristic which makes it an attractive concept in theory.

PAWA, however, does not intend to apply the Ramsey approach because its application requires in-depth knowledge of demand responses. Moreover, it would create equity problems, and is unlikely to be acceptable to customers who may not be convinced of the rationale for price differentiation based on demand rather than cost characteristics.

Instead, PAWA proposes allocating common network costs (including sunk costs) according to the peak-demand cost characteristic (peak kVA per customer per period) and energy use — this is an FDC method of allocation.

There may be criticism of FDC allocations because they can alter investment and consumption patterns *vis á vis* more efficient allocation methods, and they are considered too arbitrary. PAWA, however, considers that due to broad similarity of demand characteristics within customer groupings its FDC approach is unlikely to lead to inefficient investment, and nor is it likely to have a large impact on consumption patterns. There is a possibility that some commercial and industrial customers would be charged a lower rate under a Ramsey allocation due to their higher price sensitivity, but this would entail some other consumers paying a higher proportion of common costs which is not considered likely to be acceptable to customers as it could be perceived as introducing an element of cross subsidy. Further, an FDC approach is unlikely to adversely impact generators' location decisions given that the need to locate close to fuel supplies and the customer demand point is a much more important consideration.

An important option that PAWA would like to reserve is the option to negotiate with commercial users considering by-pass. This will enable its FDC allocation to mimic the effect of Ramsey pricing for such customers. However, prices should never fall below direct marginal cost — if prices need to fall this low to avoid by-pass then by-pass is efficient. Using this approach, there should be relatively minor inefficiency implications arising from allocating joint and common costs and sunk costs on the basis of energy or kVA.

4.4.2 Not allocating all fixed costs on a peak kVA basis, should reduce the difference between distributed cost approach and marginal cost pricing

FDC allocation of all network costs according to kVA could over-signal incremental costs as —

a) there are interdependencies in the network. Many customers benefit from augmentation because this generally improves reliability and load flow and hence it is difficult to identify specific benefits. However, this does create a rationale for not attributing all of the incremental cost to each increment in demand;

b) future load growth costs are included in current infrastructure costs. Due to the lumpy nature of some types of augmentation, larger increments in capacity than required to meet demand growth expected in the near future are often appropriate. The associated cost should be spread over all of the forecast increases in demand.

c) to the extent that future (i.e incremental) capital costs are lower than the cost of sunk assets, recovering sunk fixed costs may also lead to over-signalling incremental costs.

Hence only part of the fixed network costs are allocated in this fashion. The remainder is recovered on an energy (cents per kWh) basis. Further, NECA (1999, p. 44) in its recent review of network pricing stated that it is appropriate to simply apply discretion when determining the proportion of fixed costs that should be allocated on a peak energy basis —

> *There should be a substantive peak demand-based element to the DNSP pricing structure in all jurisdictions. … we recommend that the precise form of that element and the proportion of total charges determined by it should be left to the jurisdictional regulator's discretion.*

PAWA agrees that discretion is required, and it should be noted that recovery of fixed network costs in this fashion is consistent with the approach adopted by a number of other networks.

4.4.3 PAWA proposes the network tariff retains the structure of the standard demand tariff

PAWA has recently reformed its tariff schedule through the introduction of the standard demand tariff schedule with resulting significant improvements in load factor and power factor. Large and generally contestable customers are familiar with the new tariff schedule and PAWA is reluctant to significantly restructure the tariff unless it can be shown that this will lead to real efficiency gains. PAWA considers that its proposed network tariff structure has many similar characteristics to LRMC pricing. Where the characteristics of PAWA's proposed tariff differ from LRMC pricing it is considered that higher levels of administrative efficiency and equity considerations more than offset any loss in efficiency.

4.5 WHAT IS THE IMPACT ON PRICE STABILITY?

IPART (1999) determined that retail franchise prices in (i.e. bundled prices for generation, network and retail services) NSW should not move outside a set of defined limits.

As the PAWA tariffs are calculated on the basis of the components within the revenue cap they are unlikely to increase by more than similar bounds, and because there is some growth in demand and energy anticipated, it is not envisaged that any individual prices will move faster than the CPI once this new regime is introduced (GST impact aside).

Large price fluctuations during the regulatory period are not anticipated. If however, there is need to vary the revenue cap as a result of unforseen circumstances, such as the increase in a cost factor outside PAWA's control, then this may cause excessive variability in prices. As mentioned in PAWA's previous submission on the determinants of the revenue cap, it may be necessary in such cases to spread the adjustment to the revenue cap over a number of financial years in order to avoid prices following a saw tooth pattern. This would help ensure prices stayed within appropriate guidelines.

As discussed in Section 3.3 there may be some price fluctuations during the initial regulatory control period. However, PAWA does not have an estimate of the price fluctuations, and it will not be until the revenue cap and pricing principles have been established that any initial estimates of price fluctuations will be known. PAWA considers that the regulator could apply an appropriate transitionary strategy in the event that any expected "initial" price fluctuations are excessive.

4.6 WHAT IS THE IMPACT ON THE NET FINANCIAL POSITION OF THE GOVERNMENT, INCLUDING CSO PAYMENTS?

The net financial position of the Government will be significantly affected if —

a) the regulator agrees with the proposed approach for allocating costs. i.e. all customers should contribute an equitable share of costs; and

b) the Government decides to insulate residential consumers from the resulting higher embedded network charge, as presently industrial/commercial consumers make a larger contribution per kWh (after allowing for their lesser use of the low voltage network).

In this case, the Government would need to make a transparent CSO payment equal to difference between the network charges allocated to residential consumers and the amount of network charges implicitly recovered through tariffs set by the Government. This calculation could only be done after generation prices and retail margins are agreed by Government. This is therefore a matter wholly within Government control.

4.6.1 The direction of any deviation from FDC pricing

If PAWA's proposed FDC approach for allocating common costs is not accepted by the regulator, then any alternative approach should be consistent with the pricing principle espoused by the IUC (2000) — i.e. that "recovering the difference between marginal and average costs in the least distorting manner possible". This means that any change in the share of costs borne by different customer groups away from the FDC allocation should be in the direction of Ramsey pricing.

That is, there is no rationale for requiring a group of customers insensitive to price changes to make a smaller contribution to costs than a group of customers who are sensitive to price changes.

Moreover, if a group of customers that are insensitive to price changes are required to make a large contribution (relative to an FDC allocation) to common costs, this contribution should be roughly in line with the standard Ramsey formula. In effect, this means that a group of customers should not be required to pay substantially more than other customers, if they are only slightly less responsive to price changes.

4.6.2 An equitable share of network costs does not mean a uniform per kWh charge

The allocation methodology, as detailed in Section 3, is considered to be cost reflective and equitable, as the allocations are made on the basis of the principal cost drivers (i.e. demand and energy). However, under this approach domestic customers would pay a higher amount per kWh than larger customers in reflection of —

- large users' lesser use of the low voltage network (Table 3 shows how this is accounted for in the FDC process). This part of the network is more extensive and hence requires more maintenance than the high voltage network. (To a large extent these costs are not common between domestic and commercial/industrial user groups, and hence these costs should always be reflected in the amount of network costs attributed to domestic users); and

- residential customers have poorer load factors. Allocating according to kVA means the charge per kWh is higher for customers with a poor load factor, and peak kVA is one of the principal cost drivers used.

4.6.3 Does the cross subsidy definition provide a potentially wide band of acceptable tariffs?

This definition relates mainly to predatory pricing, and is one of a number of aspects of efficient pricing. If the aim is to "Recover the difference between marginal and average costs in the least distorting manner possible", as espoused in the IUC's pricing principles paper, then this restricts prices to a narrower band than the cross subsidy rule. Consequently, the cross subsidy definition cannot be used to justify a decrease in residential users' share of common costs.

4.6.4 Net financial impact

If the NT Government wished to insulate domestic tariffs from any price fluctuations resulting from implementation of the proposed tariff schedule, then this would clearly require a CSO payment to PAWA.

On the other hand, the Government should receive a dividend of say 50 per cent of the after tax network profit, whereas it has not received a very substantial dividend from PAWA in the past. If PAWA Generation and Retail are also required to earn a normal return to capital and make a dividend payment to the Government as owner then this will also represent a payment to the Government that it did not receive in the past.

5. EXCESS NETWORK USAGE CHARGES

Network access prices established within the revenue cap determined by the regulator are to be based upon the expectation that the network user's —

- actual demand at a connection point does not exceed the contract maximum for that connection; and
- the quantity of electricity transferred to the electricity network for or on behalf of the user at the connection does not exceed the declared sent-out capacity from the user in respect of that connection.

Where these limits are exceeded, excess charges not subject to the network revenue cap will apply in accordance with the methodology espoused in Schedule 11 of the *Third Party Access Code*. PAWA considers that this methodology is appropriate in principle, but does question the exact formulation of the charge. The charge is defined in the Schedule as —

$$\sum_{i=1}^{i=n}(A_i / B \; * C * D)$$

where —

A_i (in kW or kVA) is the highest excess entry point network usage amount for any of the energy usage periods which fall within excess network usage period I;

B (in kW or kVA) is the declared sent-out capacity for that entry point;

C (in $) is the use of network change in respect of that entry point for the month;

D is the excess network usage factor set out in the network pricing schedule for the financial year in which the month falls;

"i" is the excess network usage period; and

"n" is the number of excess network usage period during the month.

To give effect to the methodology, PAWA is required to report D in its Pricing Schedule. The objectives PAWA considers should be applied for setting the excess network usage charge are similar to the objectives for determining the out-of-balance power sale price. That is, due to the imminent augmentation investment signalled by very high capacity utilisation, there should be sufficient price signals in the form of penalties to deter generators and load users from exceeding their nominated maximum demand levels. The factor that PAWA nominates will be consistent with this general principle.

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