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Ontario Hydro Services Company Inc.

Transmission Rate Order Application
to the
Ontario Energy Board

1999-2000

December 7, 1998

Transmission Rate Application: 1999-2000

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1.0 EXECUTIVE SUMMARY

This Application marks the beginning of the regulation of the Ontario Hydro Services Company Inc.'s (OHSC) transmission business by the Ontario Energy Board (OEB). It is made in the context of the Ontario Government's restructuring of the electricity industry to introduce competition to the generation and retailing sectors, and regulation to the transmission and distribution sectors of the industry.

In this Application, OHSC asks the OEB to grant an order approving a revenue requirement for the transmission business and rates derived from that revenue requirement for unbundled transmission services to customers for the year 1999. For the year 2000, OHSC asks the OEB to grant an order approving the performance-based regulation (PBR) mechanism and the transmission rates derived from that mechanism. This Application is made pursuant to section 129 of the *Ontario Energy Board Act, 1998* (Act), and is consistent with the anticipated conditions applicable to the Company's as yet unissued transmission licence.

Ontario Hydro Services Company Inc. is a successor company to Ontario Hydro, and will become operational as of April 1, 1999. OHSC is a commercial entity incorporated under the Ontario *Business Corporations Act* with a single shareholder – the Province of Ontario. It will structure itself as a holding company which will be the parent of a subsidiary containing the transmission and distribution businesses. Although the Application is filed by OHSC, once the subsidiary is legally established, the Company requests that any order made pursuant to this Application be issued to the subsidiary.

The high-voltage transmission assets and associated support systems belonging to the former Ontario Hydro will be transferred to OHSC as the physical base of its transmission business. This consists of lines and transformer stations and supporting facilities operating above 50 kV. For rate design purposes, these facilities are separated into two functions: network and connections.

During the transition period to open access, and to the end of the year 2000, wholesale rates are subject to the Government's rate freeze. The Company's Application is consistent with this Government policy.

Ontario electricity customers will pay a bundled wholesale rate during the transition period, and the revenues collected on a bundled basis will be allocated to the successor companies of the former Ontario Hydro. In the case of OHSC and its transmission business, the revenue requirement that is approved as the basis of bundled transmission rates will be used to allocate revenue. For Ontario customers, the unbundled transmission rate will not be implemented until the arrival of open access.

In support of its Application, OHSC has calculated a revenue requirement for the year 1999. For 2000, the Company is proposing that the rates and revenue requirement be set using PBR framework. Consistent with this framework, OHSC is proposing quality of service safeguards to ensure that existing standards are maintained.

The proposed revenue requirement for 1999 is $1,327 million (M) and the PBR framework forecasts a revenue requirement for 2000 of $1,291M. Based on these forecast revenue requirements, the following transmission rates are proposed:

	1999 $/kW/month	2000 $/kW/month
Network	1.19	1.16
Connections	4.04	3.89

In arriving at the proposed revenue requirements, the Company has made certain assumptions on issues that may be addressed by future recommendations of the Market

Design Committee, by the Operating Agreement between OHSC and the Independent Electricity Market Operator, by Government policies and directives, and by the final form of the transmission licence.

The restructuring of the electricity industry in Ontario redefines the role of the transmission business. OHSC is reconstituting its transmission business at every level – capital structure, asset sustainment, organization of the business, and relationships with its customers, the regulator and the industry.

OHSC will have a commercial capital structure, and will have to secure access to competitive financing. It will have a shareholder to which it will pay dividends, and it will pay taxes. The way in which the business is organized and directed will have a fully commercial orientation. This will drive efficient decisions on allocation of resources, conducting work, relations with customers, and enhanced productivity.

The condition of the asset base is being reassessed with a view to sustaining its value over the long term. OHSC will commit resources for short-term restoration as well as long-term sustainment.

With respect to the organization of the business, OHSC is changing the fundamental relationship between the assets and the work carried out to restore, maintain, sustain, develop and expand them. An asset management model is being evolved that will eventually lead to the sourcing of services for the assets on a fully competitive basis.

OHSC looks forward to establishing a progressive relationship with the regulator and stakeholder community in Ontario as it moves forward to a newly-restructured environment.

5.0 REGULATORY FRAMEWORK

OHSC is proposing to use a cost of service (COS) framework for setting the transmission business revenue requirement and rates for 1999, and a performance-based regulation (PBR) framework (in the form of a "Revenue Cap") for 2000.

The following Section describes the COS framework for 1999. This is followed by a description of the proposed PBR framework for 2000. The Company's asset base and revenue requirements are presented in Chapters 7 and 9. The quantification of the PBR parameters is then presented in Chapter 10.0 - Setting the Revenue Cap.

5.1 Cost Of Service (COS)

The regulator's mandate is to ensure that rates charged for the transmission business and distribution services are just and reasonable.

To meet these objectives, regulators have established a framework, complete with specific rules and procedures to which utilities must adhere when determining the rates they charge their customers. Traditionally this has been a cost of service framework.

The concept of the **"Test Period"** and the related **"Revenue Requirement"** is the starting point in the determination of utility rates. The Test Period usually corresponds to the utility's financial reporting period, which may be the calendar year or any 12-month period. Multi-year test periods may also be used. The Revenue Requirement may be defined as a sum of the utility's costs for:

- operations, maintenance and administration;

- depreciation on assets used to provide utility service;
- interest incurred in financing utility assets and operations;
- income and other taxes;
- a just and reasonable return on equity (profit) as determined by the OEB; and
- any other expenses incurred to provide utility service.

In utility rate-making, the profit is considered to be a cost of the utility because it is an amount due to shareholders in return for financing the portion of utility assets and operations not financed by debt.

Offset against the sum of costs may be revenues from services or functions provided to other organizations, companies, or customers that are not strictly speaking, basic utility service. Such revenues might include late payment penalty revenue, revenue from service work on customer premises, revenue from services provided to affiliate companies, and facility charges. Offsetting these costs against the revenue requirement ensures that the total costs to be recovered by the utility rates do not include anything other than basic utility service. This is necessary because the utility will receive revenue from other charges directly to cover the non-basic services.

The costs included in the revenue requirement are fairly straightforward except for the profit provision. The way the regulator establishes a reasonable profit is to determine what financing for utility assets and operations is required. This is generally called the **Rate Base**. The regulator would then determine what portion of the Rate Base was financed by the utility shareholders (equity) and what portion was financed with debt. The regulator would then set the profit provision by allowing for a rate of return on the shareholders' equity portion of the Rate Base. In this Application, OHSC is requesting a 10% return on the equity investment provided by its shareholder, the Province of Ontario.

The concept of the Rate Base is one that is unique to the regulated industry. The major components generally comprising the Rate Base are:

1. the utility's investments in utility fixed assets including assets such as lines, poles, transformer stations, and buildings,

2. other assets such as meters, service vehicles, computers, and office equipment, and,

3. an allowance for working capital, including average amounts invested in inventories of operating materials.

Working capital is needed to "bridge" the time gap between the payment of utility operating expenses and the subsequent receipt of rate revenues. In this Application, OHSC has not calculated a detailed provision for working capital. While OHSC is under transition, such a calculation is not only difficult, but may also be inappropriate, as it can only be done for Ontario Hydro as a whole. Further complicating this issue is the fact that the Government's pending response to MDC recommendations and the pending agreement between OHSC and the IMO could significantly affect working capital requirements. Once OHSC is operational, the market structure fully defined, and OHSC's own financial systems in place, the Company may be able to calculate a detailed provision for working capital.

After determination of the Revenue Requirement for the Test Period, a comparison is generally made to the expected rate revenue from current rates to determine the existence of a revenue surplus or a deficiency in the Test Period.

A revenue deficiency will usually cause the utility to file a request (supported by the above Revenue Requirement data) to the regulator for an increase to its existing rates. In OHSC's case, this Application is filed to obtain approval of the forecast revenue requirement. In this Application, OHSC is not proposing any changes to the bundled rates charged to customers because of the wholesale rate freeze.

The regulator retains the final authority over whether to accept or reject the Company's request for the Revenue Requirement. In respect of this Application, which is the first filed by OHSC, the legislation requires that no rate order be issued without the prior approval of the Minister of Energy, Science and Technology.

5.2 Performance-Based Regulation (PBR)

Incentive-based regulation, also known as performance-based regulation (PBR), is a form of economic regulation that can be used to control the prices and service quality of public utilities. PBR sets performance targets and provides incentives for the regulated company to meet or better targets. Customers benefit from the productivity improvements incorporated in the mechanism. The scheme also motivates utilities to reduce costs and operate more efficiently by allowing them to benefit from the efficiency gains.

Many regulators throughout the world are adopting PBR as the preferred regulatory approach. The Ontario Government, in its White Paper, directed the OEB to "implement a performance-based approach to regulation that ensures efficiencies are achieved in the monopoly parts of the industry and result in benefits to the customers".

Cost of Service regulation sets prices to allow utilities to recover their reasonable costs plus a fair return on their investments. Especially where the rates are reviewed annually, the incentive to operate more efficiently is reduced, because generally, costs are allowed to pass through to customers. PBR attempts to break the link between costs and prices. The ability to increase profits through cost reductions provides a strong incentive to operate more efficiently.

PBR attempts to correct some of the drawbacks associated with Cost of Service regulation by:

- providing better operational efficiency incentives to minimize costs and improve productivity
- sharing the benefits of efficiency gains between customers and shareholders
- discouraging "goldplating" or over investment in capital
- providing incentives to take risks and be innovative
- minimizing administrative complexity, regulatory costs and time, and reducing the frequency of regulatory reviews

PBR plans must be properly designed to ensure just and reasonable rates and reliable service. The OEB has developed the following principles[1] for the implementation of PBR:

1. The PBR framework should address all the specific requirements of the legislation and regulations.

2. The PBR framework should protect customers and result in prices for regulated services that are just and reasonable.

3. The PBR framework should discourage cross-subsidization between regulated and competitive services.

4. The PBR framework should encourage greater economic efficiency by providing the appropriate pricing signals and a system of incentives to maintain an appropriate level of reliability and quality of service.

[1] Principles stated in memorandum to Ontario Energy Utilities from the OEB entitled Re: Development of PBR for Regulated Energy Utilities in Ontario, dated October 2, 1998.

5. The PBR framework should permit the utility an opportunity to earn a reasonable return on shareholder capital and to maintain its financial viability.

6. The PBR framework should be as simple as possible. The cost of administering PBR, including the costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available from PBR.

7. PBR should allocate the benefits from greater efficiency fairly between the utility/shareholders and the customers.

8. The PBR framework should be flexible and able to handle changing and varied circumstances.

9. The PBR framework should facilitate the use of efficient processes.

These principles were considered in the development of this PBR proposal. Furthermore, OHSC believes the customer will benefit most if the principles for PBR also provide the Company with strong incentives to operate efficiently, be innovative, and give customers good value of service. The PBR framework should also be designed to promote price and revenue stability.

5.3 Performance-Based Regulation Proposal

5.3.1 Form of PBR

OHSC proposes that performance-based regulation in the form of a "Revenue Cap" be used for the economic regulation of the monopoly components of the Company's transmission services business for the year 2000. Under the plan, the maximum allowed revenue that the Company can receive for transmission services is capped for the duration of the control period (i.e. the year 2000) with suitable adjustments for inflation, expected productivity improvements, and system growth. The proposed plan includes service quality safeguards.

Three basic types of PBR were considered for the Company's transmission business:

- Cost of Service Regulation with Targeted Incentives,
- Price Cap Regulation, and
- Revenue Cap Regulation.

An analysis of these options is presented in Appendix J - PBR Options.

Cost of Service (COS) with Targeted Incentives applies incentives to some targeted aspects of the Company's cost structure (e.g. OM&A reductions). However, a plan that provides incentives to reduce OM&A costs and not capital costs would provide inappropriate motivation to replace aging facilities rather than fix them. Therefore, this type of incentive plan is not the first choice because it does not provide incentives to realize **overall** efficiency gains that require changing relative cost structures. It also requires a relatively heavy administration load (i.e. two different forms of regulation applied to the Company at the same time) and many assumptions regarding controllable costs, individual cost drivers, and indexes. This runs counter to the objective of a more efficient approach to regulation.

A Price Cap has the advantage of being comprehensive but is not viewed as favourably as a Revenue Cap because, under a Price Cap, revenues would vary with the use of the transmission system (sales). This is less suitable for the transmission business because costs in the short term do not vary significantly if transmission business usage drops. If the use of the transmission system drops, the operating costs, depreciation, and cost of capital remain virtually the same in the short term, putting the Company at a financial disadvantage. Also, a Price Cap would provide artificial incentives for the Company to plan and operate its business in a way that would boost peak demand for electricity and thereby provide disincentives to participate or invest in load management initiatives.

Under the proposed Revenue Cap plan, the maximum allowed revenue that the Company can receive for transmission services is set for the duration of the control period (i.e. year 2000) with suitable adjustments for inflation, expected productivity improvements, and growth according to the following formula:

Proposed Revenue Cap Formula

$$R_t = R_{t-1}(1 + I - X + GAF) \pm Z$$

where

R_t = Revenue in year t

t = year in which revenue cap control applies, starting in year 1 to end of control period

R_{t-1} = Revenue in year t-1

I = Inflation Factor

X = Productivity Factor

GAF = Growth Adjustment Factor

Z = Z Factor (costs from unforeseen exogenous events or special one-time events)

For this Application, the base year will be the year 1999. The base year would be set following the OEB's determination of the revenue requirement for 1999 on a cost of service basis. This is consistent with standard practice for setting the base year for establishing PBR for subsequent years.

5.3.2 Scope of PBR

The revenue cap applies to "Transmission Services" which the Company is licensed to carry out. The Transmission Services, which are to be defined in the Company's yet to be issued transmission Licence, include the planning, development, construction, maintenance, and operation of the transmission system (both Network and Connection) for the transport of electricity. Transmission Services may be excluded from the PBR formula if they are considered competitive, or if their costs or prices are difficult to predict and another form of regulation is considered more appropriate.

There are no excluded Transmission Services proposed during the period under consideration.

5.3.3 Duration

The duration of this Application is limited to the years 1999 and 2000, unless extended by the OEB. The proposed base year for the PBR plan is 1999. The PBR indexing formula is used to calculate the year 2000. The revenue requirements and rates for 1999 are based on cost of service regulation. The annual revenue cap and rates for 2000 are to be calculated prior to 1999 using an updated inflation factor. The values of X (productivity factor) and GAF (growth adjustment factor) are determined at the outset of the formula.

Under conventional application, PBR spans a period of four years or more. OHSC is proposing to use PBR for the year 2000 to begin developing the base of experience to evolve, develop and refine a PBR approach in coming regulatory reviews and learn how best to implement PBR in Ontario.

5.3.4 Base Year Revenue Requirements

There is no established historical base year revenue requirement for the newly defined transmission business as the new OHSC comes into existence in 1999. It is, therefore, proposed to use 1999, as set by the OEB, as the base year for the PBR plan.

5.3.5 The Inflation Factor

The inflation factor in the formula, "I" accounts for increases in Company costs due to inflation in general price levels, which are out of the Company's control. The inflation index proposed for use in the formula is the Ontario consumer price index (CPI). This index is proposed because it is readily available, relies on external data, is understandable, and is well accepted.

The use of a customized inflation index constructed as a weighted index of the prices of inputs to the Company was considered but not recommended at this time because it is not readily available and is complicated to develop.

If a customized inflation index is to be used it should be specific to the transmission industry and it should be used in conjunction with a productivity factor. A transmission industry specific productivity factor is not readily available at this time.

5.3.6 The Productivity Factor

The productivity factor "X" in the PBR formula accounts for the productivity improvement the Company is expected to make over the control period. All of the benefits from this expected productivity improvement are passed on to the customer. The

X factor lowers the revenue requirement and rates derived from it, from what they would otherwise be.

For the interim control period, OHSC proposes that the X factor be based on the change in its forecast revenue requirements from 1999 to 2000 (excluding variation for inflation and growth). The resulting value of X represents the Company's estimate of productivity gains it will strive to achieve.

Alternatively, the productivity measurement could be based on historical Company data, transmission industry data, or external benchmarks. These measures are not readily available at this time. The use of external measures should be considered for future control periods. Only an initial or base revenue requirement would be needed upon which the inflation, productivity and growth indices could be applied to predict future revenue requirements in the control period.

5.3.7 The Growth Adjustment Factor (GAF)

The growth adjustment factor "GAF" in the PBR formula adjusts revenues for growth in transmission services provided. The proposed GAF for the interim control period is the annual weather corrected growth in the forecast system peak demand for power in the Province. The peak demand is proposed because it is the major driver for system expansion.

The GAF is forecast and fixed for the control period. The use of a forecast rather than actual GAF is recommended because it minimizes adjustments within the test period and provides rate stability.

Other options for determining the GAF include the number of customers served and the amount of energy delivered on the transmission system. However, the number of customers served does not accurately reflect costs and revenue requirements because of the large variation in costs associated with different size customers. The amount of energy delivered depends upon the cumulative quantity of flows over the system, and it is primarily peak demand, not utilization flows, that drives the need for transmission expansions and the bulk of the transmission business costs.

5.3.8 The Z Factors

The "Z" factors in the formula account for positive or negative costs from either (a) unforeseen exogenous events or (b) special one-time events.

a) Unforeseen Exogenous Events

Unforeseen exogenous events are events outside of management's control. In a competitive market, the price impact of such events would normally be passed through to customers in the form of a price increase or decrease. Z factors, in effect, pass these exogenous costs through to the customer. The type of events should be specified in advance to reduce uncertainties. The proposed Z factors from unforeseen exogenous events are:

1. Externally imposed tax and accounting changes that have an impact on the Company
2. Regulatory and legislative changes and orders that have an impact on the Company (including directives for unforeseen system expansion, new service quality obligations, and industry restructuring)
3. Large uninsured accidental losses including catastrophic events, major storm damage, extended outages, environmental exposures

It is proposed that the Company would identify unforeseen exogenous Z factors as they arise, bring them forward for approval by the OEB, and have them included with interest in the next year's revenue requirements and rates. To avoid complexity and administration costs, Z factors should be considered only if they significantly impact return on equity (or equivalently impact on net income).

Some of these unforeseen exogenous event costs may have to be carried forward into a subsequent regulatory period as a special one-time event factor.

b) Special One-time Events

Z factors from special one-time events are costs from unusual, foreseen, and non-recurring events such as industry restructuring costs. These events are treated as Z factors because they are non-recurring. The proposed Z factors from special one-time events are:

1. Year end Provisions
2. Staff Provisions

It is proposed to estimate the costs for these special one-time events and include them as Z factors in the revenue cap formula when the revenue cap is initially set.

5.3.9 Determining the Future Revenue Requirement

Against the base revenue requirement set by the OEB, the approved indexing formula (i.e., inflation, productivity and growth indexes) can be applied, to predict the future revenue requirement in the control period. This enables the annual revenue cap and rates to be calculated and published for each year, before that year begins.

Within the indexing formula, the values of X and GAF are predetermined. The value of the inflation factor I (CPI) is to be updated using a recent forecast of CPI.

5.3.10 Applying PBR During the 1999-2000 Period

The methodology for applying PBR during this transitional rate order period will be adapted to allow Ontario to gain the most experience from the model during the rate freeze period.

The OHSC proposal lays out the revenue requirement for 1999 as a base year for applying the PBR formula looking forward. But the proposal also lays out the forecast elements of the revenue requirement for the year 2000. Laying out the elements of the year 2000 as one would for a cost of service review will accomplish two things.

First, it allows the productivity factor to be calculated by comparing the forecast revenue requirement for 2000 with that of 1999. After factoring out inflation, the growth factor, and the exogenous and special one-time event factor, one can derive the year-over-year productivity factor.

Second, by overlaying the PBR formula elements over the year 2000 forecast revenue requirement, one can test how the PBR formula has worked in this Ontario context. By comparing the year 2000 forecasts with the formula projections, one can determine how the elements of the revenue formula have interacted with each other and how the formula has performed overall to capture the range of discrete forecast elements that would go into a cost of service treatment.

5.3.11 The Benefits of Incorporating a PBR treatment into this Initial Rate Order

The Government's White Paper called for the pursuit of more efficient regulation through performance-based regulation. The Ontario Hydro Services Company believes that the current context of the rate freeze and the two-year limit on this initial rate order provides an ideal context in which to carry out the first initiative in implementing performance based regulation in electricity.

The rate freeze to the end of 2000 ensures that the rates customers pay will not vary during this interim period regardless of the regulatory framework. The two-year time frame for PBR, while too short a working span for a mature regulatory regime, provides an appropriate test period for those familiarizing themselves with how this particular PBR formula might work in Ontario. The two-year period provides an opportunity to gain experience with PBR in a context which isolates customers from potential "glitches" of a prototype run.

PBR frameworks usually require the development of customer protection standards on the services side of the business. OHSC has in place transmission service standards, and is working to develop those further. Customers will benefit from that initiative.

A key aspect of PBR is the establishment of commercial incentives to drive more innovation and efficient ways to carry out work within the regulated business. The Ontario Hydro Services Company regards this as a fundamental commercial driver to establish in the new company -- one that will benefit customers as well as OHSC.

Finally, OHSC recognizes that it is important to support the OEB in developing new and more efficient methods of regulation. OHSC is committed to on-going support for the regulator's PBR initiative in distribution. The launch of performance-based regulation for the transmission business will provide the opportunity for the regulator, OHSC and stakeholders to work toward assessing and developing the best approach for PBR for the transmission business.

5.3.12 Quality of Service Safeguards

It is important that as the electricity industry in Ontario is restructured, the quality of service levels which transmission users have come to expect be maintained[2]. Quality of service for the transmission business is primarily centered on the reliability and availability of the transmission system, which can be reflected in measures based on the frequency and duration of outages that affect the transmission system. Related to the duration of outages is the magnitude of the loss of energy supply.

The Company has used the concepts described above to develop a proposed set of performance measures which address both the quality of service that directly impacts load customers and the quality of service that relates to the efficient operation of the market. Care has been taken to ensure that the performance measures selected are measurable, comparable and provide a balanced set that complement each other. It is important to recognize however, that in some instances satisfying one performance measure creates unavoidable tension with other measures.

The use of performance measures in a regulatory context, or as part of a performance management process for the Company, is relatively new. In the past, Ontario Hydro has maintained levels of reliability without the performance measures proposed by OHSC here. Adoption of the proposed performance measures will require a transition period for their implementation as the basis for driving the Company's commitment to plan, maintain, and operate the transmission system. The Company fully expects that new information will surface as the electricity industry restructuring proceeds. Therefore the measures described herein may be altered or new performance measures developed to reflect learning by the Company or changes in regulation.

[2] *Ontario Energy Board Act, 1998* specifies that one of the objectives that will guide the OEB is "to protect … the reliability and quality of electric service".

The targets for all performance measures have been set based on the goal of maintaining the performance of the Company's transmission assets at historical levels. The historical performance provided in the following section indicates that for most measures there is a high variability in the results. This variability is due in large part to the fluctuations in weather and the high impact of occasional equipment failures. To accommodate this wide historical variability and prevent any degradation of service, OHSC intends to achieve performance that is better than a minimum threshold defined by experience over the past ten years.

The four customer commitment performance measures and one market efficiency performance measure that the Company is proposing to track and report are discussed in detail below. The discussion below includes the definition, 10 years of historical performance and the target for each performance measure.

5.3.12.1 Customer Commitment Performance Measures

The following four measures focus on the service provided at the delivery points where energy is transferred from the Company's transmission system to a distribution system or retail customer.

1. Frequency of Delivery Point Interruption

The Frequency of Delivery Point Interruption measure is an overall transmission system indicator of the reliability of service provided to transmission customers. The measure is calculated as the total number of interruptions at all delivery points divided by the total number of transmission delivery points.

The total number of interruptions includes the impact of all momentary and sustained interruptions caused by either forced or planned transmission outages, but excludes outages resulting from force majeure events. Similar frequency-related measures used by the electricity industry will typically exclude the impact of momentary interruptions. However, the Company has chosen to include them because momentary interruptions can have significant negative impact on some customers. Similarly, the impact of planned outages is sometimes excluded from interruption frequency-related measures because of the fact that planned outages can be coordinated with customers to minimize impacts. The Company, however, has chosen to include planned outages because in some instances customers are inconvenienced by interruptions, even if planned.

This measure is expressed mathematically as:

$$\text{Frequency of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}(M_i + S_i)}{N}$$

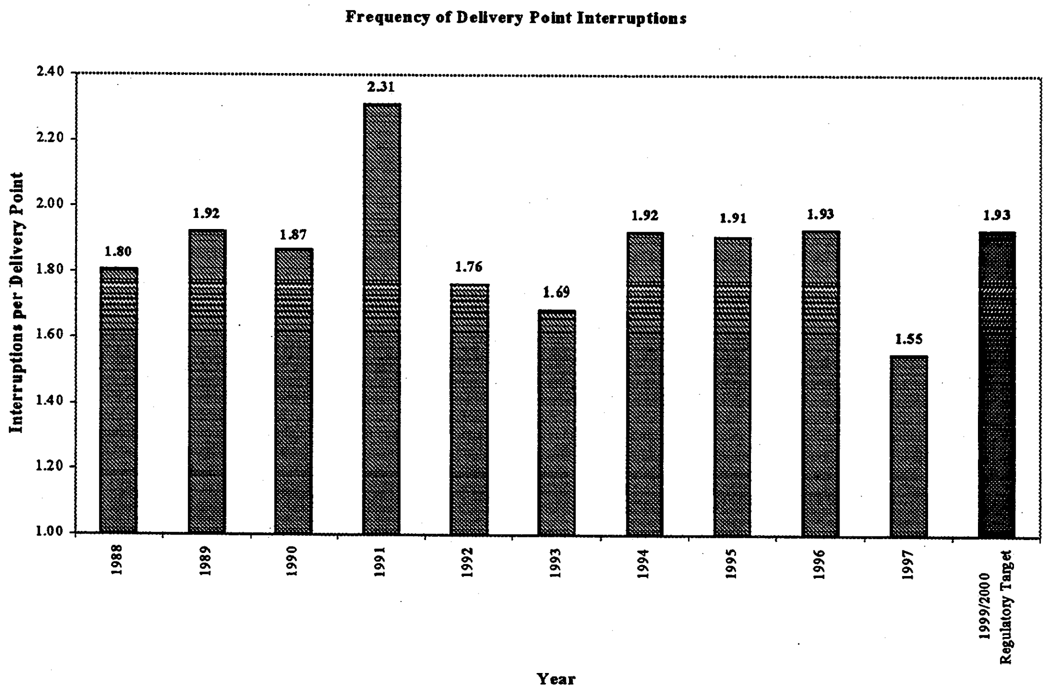
Where:

- M_i is the total number of Momentary Interruptions experienced at Delivery Point i over a one year period.
- S_i is the total number of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a one year period.
- N is the total number of Delivery Points at year-end of the reporting period

Historical Performance and Target

Performance from 1988 to 1997 is in the range of 1.55 to 2.31 Delivery Point Interruptions per year as indicated in the chart below. Note that force majeure events have not been excluded from the historical data. However, the inclusion of these events does not materially impact the historical data.

An annual threshold target of 1.93 Delivery Point Interruptions per year is proposed for this measure. OHSC intends to achieve performance that is better than this target.



2. System Minutes of Unsupplied Energy

System Minutes of Unsupplied Energy combines the impact of duration of outages with the energy that is not supplied to a Delivery Point as a result of the outage. The measure is calculated as the energy not delivered to customers due to sustained delivery point interruptions caused by either forced or planned outages of transmission (excluding outages resulting from force majeure events). It is designed to be comparable with other transmission providers by dividing the energy not delivered with the annual system peak.

Similar industry measures will sometimes exclude the impact of planned outages, however, the Company has chosen to include this impact because if a planned outage results in the non-delivery of energy which would otherwise have been consumed, then there clearly is an impact to the transmission customer.

This measure is expressed mathematically as:

$$\text{System Minutes of Unsupplied Energy} = \frac{\sum_{i=1}^{N} U_i \ x\ 60 \text{ min/hr}}{Pk}$$

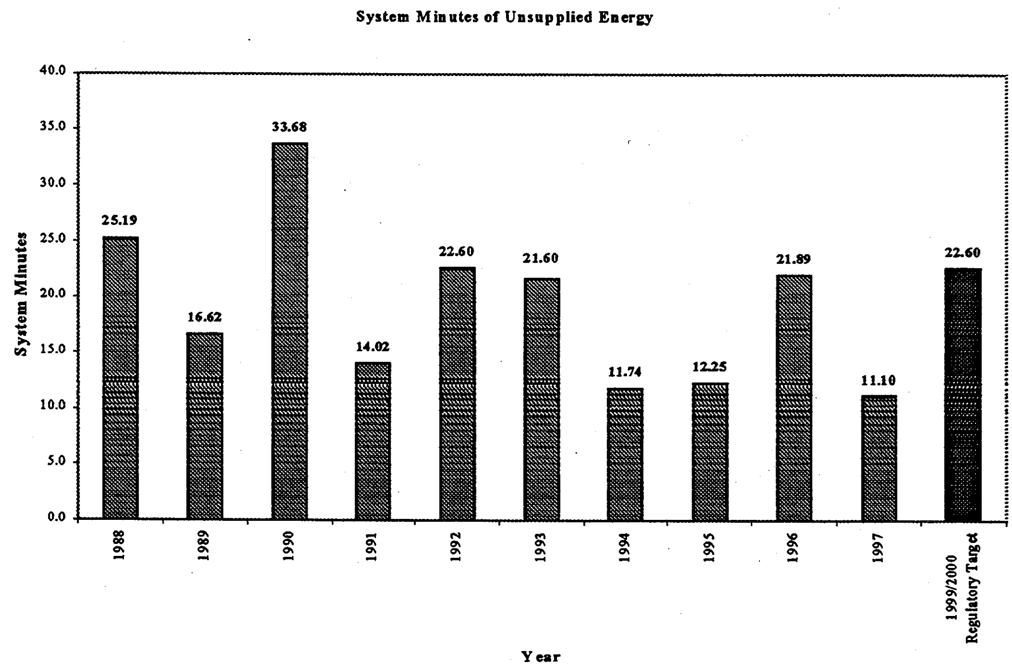
Where:

- U_i is the total unsupplied energy, expressed in MWh, at Delivery Point i over a one year period.
- Pk is the transmission System Peak, expressed in MW.
- N is the total number of Delivery Points at year-end of the reporting period.

Historical Performance and Target

Performance from 1988 to 1997 is in the range of 11.1 to 33.7 system minutes of unsupplied energy. Note that force majeure events have not been excluded from the historical data. These events will have an impact on some of the historical data.

An annual threshold target of 22.6 minutes of unsupplied energy is proposed for this measure. Note that because of the occurrence of a force majeure event that impacted the 1988 results, the target was determined based on the results from 8 out of 10 years. OHSC intends to achieve performance that is better than this target.



3. One Hour Restoration Commitment

The One Hour Restoration Commitment is an indicator of how the Company responds to a customer's emergency needs. This measure provides a driver to expedite the restoration of sustained interruptions causing load loss and reflects the historical level of service customers have received.

This measure is calculated as the percentage of sustained delivery point interruptions restored within one hour. The measure includes the impact of both planned and forced transmission outages, but excludes outages resulting from force majeure events.

This measure is expressed mathematically as:

$$\text{One Hour Restoration Commitment} = \frac{\sum_{i=1}^{N}\left(S_i \text{ restored in} \leq 1 \text{ hour}\right)}{\sum_{i=1}^{N} S_i} x\,100\%$$

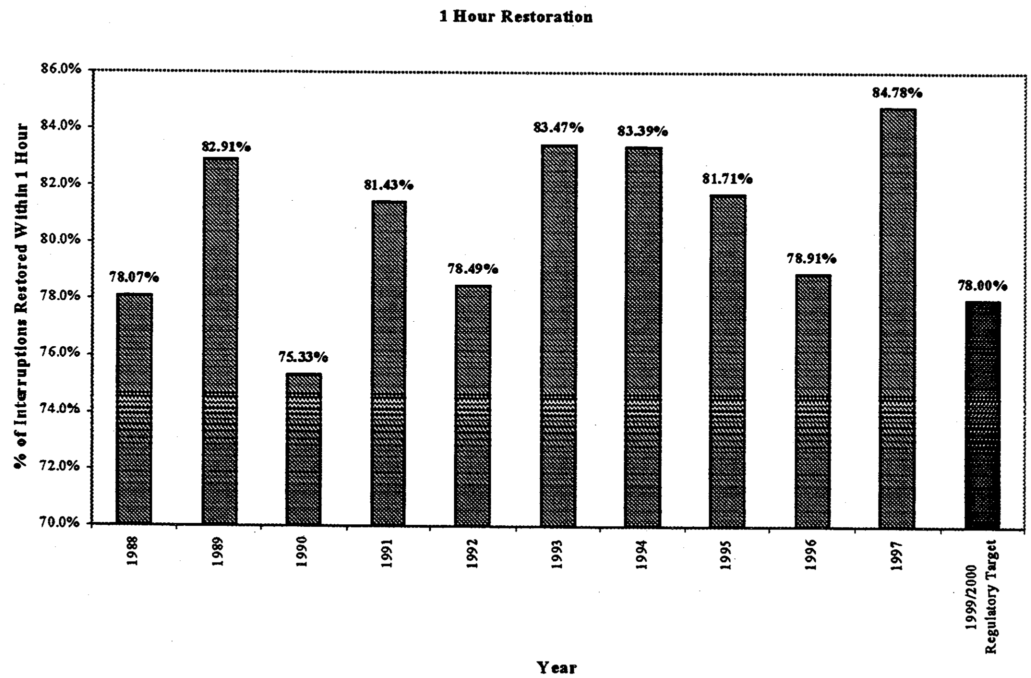
Where:

- S_i is the total number of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a one year period.
- N is the total number of Delivery Points at year-end of the reporting period.

Historical Performance and Target

Performance from 1988 to 1997 is in the range of 75.3% to 84.8% of sustained interruptions being restored within one hour. Note that force majeure events have not been excluded from the historical data, however, the inclusion of these events does not materially impact the historical data.

An annual target of restoring 78% of all Sustained Interruptions within 1 hour is proposed for this measure. OHSC intends to achieve performance that is better than this target.



4. Twenty-four Hour Restoration Commitment

The Twenty-four Hour Restoration Commitment is another indicator of the Company's response to a customer's emergency needs. This measure provides a means of monitoring the Company's efforts to ensure that sustained interruptions causing load loss will not exceed 24 hours in virtually all cases.

This measure is calculated as the percentage of sustained delivery point interruptions restored within 24 hours. The measure includes the impact of both planned and forced transmission outages, but excludes outages resulting from force majeure events.

This measure is expressed mathematically as:

$$\text{Twenty-four Hour Restoration Commitment} = \frac{\sum_{i=1}^{N}(S_i \text{ restored in} \leq 24 \text{ hours})}{\sum_{i=1}^{N} S_i} x\,100\%$$

Where:

- S_i is the total number of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a one year period.
- N is the total number of Delivery Points at year-end of the reporting period.

Historical Performance and Target

Performance from 1988 to 1997 is in the range of 99.66% to 100% of sustained interruptions being restored within twenty-four hours. Note that force majeure events have not been excluded from the historical data, however, the inclusion of these events does not materially impact the historical data.

An annual target of restoring 99.9% of all Sustained Interruptions within 24 hours is proposed for this measure. Based on the historical data, it is anticipated that this target will not be met if more than one Sustained Interruption takes longer than 24 hours to be restored. OHSC intends to achieve performance that is better than this target.

5.3.12.2 Market Efficiency Performance Measure

The Company can contribute to the efficient operation of the electricity market by limiting the time during which its transmission facilities are unavailable for use by market participants. The Company proposes to adopt the following performance measure that monitors transmission system unavailability due to forced and planned outages to its transmission facilities.

1. Transmission System Unavailability

Transmission System Unavailability measure is an indicator of the Company's contribution to the efficient operation of the electricity market. This measure will monitor the extent to which forced and planned outages on the Company's transmission circuits result in the unavailability of the transmission system for use by electricity market participants.

This measure is calculated as the total annual circuit hours not available due to forced and planned outages on all the transmission business circuits, divided by the total possible circuit hours available. Outages resulting from force majeure events are excluded.

This measure is expressed mathematically as:

$$\textit{Transmission System Unavailability} = \left(\frac{\sum_{i=1}^{N} (F_i + P_i)}{8760 \times N} \right) x\ 100\%$$

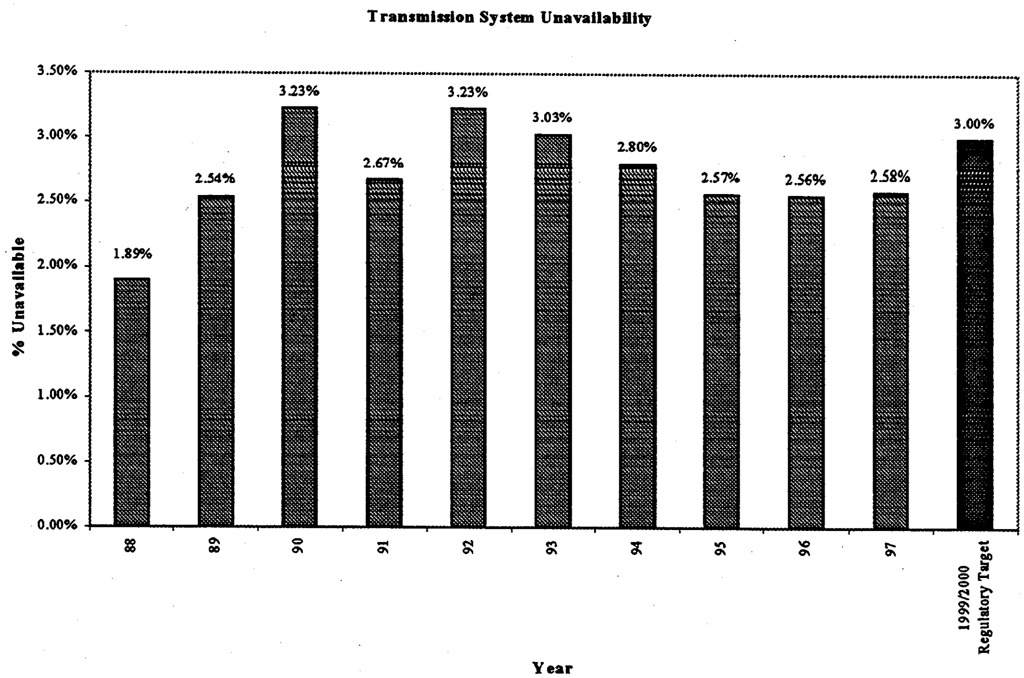
Where,

- F_i = annual forced outage duration in hours for circuit i
- P_i = annual planned outage duration in hours for circuit i
- N = total number of declared in-service circuits in the transmission system

Historical Performance and Target

Performance from 1988 to 1997 is in the range of 1.89% to 3.23% Transmission System Unavailability, as indicated in the chart below. Note that force majeure events have not been excluded from the historical data. However, the inclusion of these events is not expected to materially impact the historical data.

An annual target of 3.0% Transmission System Unavailability is proposed for this measure. OHSC intends to achieve performance that is better than this target.



5.3.12.3 Reporting

The Company proposes that for the initial Rate Order, a reasonable approach to addressing the Company's success or failure in meeting performance targets is a requirement for the Company to report its service quality performance. The regulator could then review the Company's performance against the quality of service targets and if the performance did not meet the target, there would be a review of the reasons for this. The Company would be obligated to explain to the regulator why a target was not met, and would be required to put an action plan in place to ensure that the target will be met in the future. The review process would also permit the examination of extraordinary events as well as the natural variations that could occur in a year, and on a year over year basis, which are not representative of service quality deterioration.

This approach is similar to that used in several other jurisdictions undergoing a shift to a competitive electricity market. It promotes open dialogue between the Company and the regulator, and continuous improvement on the part of the Company due to the requirement for action plans where quality of service safeguards are not met.

The proposed reporting relationships with the regulator are discussed in Section 13.2, Service Quality.

5.3.13 Transmission Performance Incentives

In its first quarter report, the Market Design Committee recommended that transmission companies be provided with incentives to "improve the capability of equipment, and operational efficiencies". The Company therefore proposes to develop suitable Transmission Performance Incentives (TPI) for application when the electricity market opens in the year 2000.

Conceptually, such incentives could be designed with particular performance targets in mind. Incentive amounts based on the expected costs the Company would incur in meeting the targets, would be included in the Company's annual revenue requirement, with an associated requirement on the part of the Company to pay out amounts to market participants, either directly or via the IMO, based on the Company's actual performance with respect to the targets during the year.

As an example, an incentive amount related to the cost of incremental transmission losses due to planned transmission facility outages could be included in the Company's annual revenue requirement. During the year, the Company would pay for the incremental transmission losses associated with removing transmission facilities from service for maintenance, or as a result of forced outages. The incentive to the Company lies in the fact that if actual outage durations during the year were actually shorter overall than the durations on which the incentive payment was based, the Company would keep the difference between the incentive payment and the actual cost of incremental losses as additional profit. On the other hand if outage durations were longer overall than planned, the Company would take a loss.

For the duration of the rate order, the company proposes inclusion of a notional TPI amount in the revenue requirement, as a placeholder for future incentive payments. During this period, this TPI payment would be paid back to the Revenue Pool, in equal monthly payments, so the net financial impact of the incentive on Company revenue would be zero.

Appendix J

PBR Options

1.0 PBR Options

There is a spectrum of PBR options, ranging from Cost of Service plans with some targeted incentives, to comprehensive Price Cap plans. This Section examines the following three basic types of PBR considered suitable for the Company's transmission business.

1. Cost of Service Regulation with Targeted Incentives
2. Price Caps
3. Revenue Caps

1.1 COS with Targeted Incentives

Cost of Service regulation with targeted incentives is the least aggressive form of PBR. It attempts to provide stronger efficiency drivers under Cost of Service regulation through the use of targeted efficiency incentives, which allows a utility to keep profits from efficiency gains earned between cost of service reviews. The efficiency incentives are typically applied to costs that are under the control of the utility and have the potential for efficiency gains. Targets for these controllable costs are specified along with financial rewards and penalties for meeting the targets.

For example, targeted incentives could be applied to a utility's operating and maintenance (O&M) costs. Rather than allow the utility to recoup all of its O&M costs through the cost of service methodology, a target is set for the O&M costs which is typically based on historical costs with suitable adjustments for inflation, growth, and expected productivity improvements. Any variations between the target costs and the utility's actual costs are absorbed by the utility. This creates a strong incentive for the utility to improve operating efficiency and reduce O&M costs. The customer benefits in the long run as lower O&M costs result in lower rates.

Some of the pros and cons of Cost of Service Regulation with Targeted Incentives are outlined below.

Pros:

- provides incentives to minimize O&M costs
- shares the benefits of O&M efficiency gains between customers and shareholders
- lessens the risks of windfall profits or losses associated with more comprehensive PBR plans by retaining overall cost of service methodology

Cons:

- provides better efficiency incentives for O&M but not for capital management activities such as capital spending, financing, and cash flow management
- does not provide incentives to realize overall efficiency gains that require changing relative cost structures.
- encourages "goldplating" or over investment in capital
- risk of windfall profits/losses if O&M costs are not set correctly
- O&M cost savings and profits may be pursued at the expense of service quality if there are no service quality safeguards in place
- social & environmental goals which do not increase profits may be less likely to be pursued
- requires heavy administration load and many assumptions regarding controllable costs, individual cost drivers, and indexes
- more complex, costly and time consuming as cost of service study still required in addition to providing targeted incentives
- does not provide pricing flexibility

1.2 Price Caps

In Price Cap regulation the maximum prices a utility charges for services are capped. Better incentives for a utility to operate efficiently are provided because prices are directly controlled, not the profits as in Cost of Service Regulation.

Price caps are determined by setting initial prices based on either the utility's existing prices, an updated Cost of Service study, or external benchmarks of prices from similar utilities. The price caps are then fixed for typically three to seven years with suitable adjustments for inflation and expected productivity improvements.

The basic price cap formula is shown below.

$$P_t = P_{t-1}\ [1 + (I - X)]\ \pm Z$$

where P_t = maximum price for group of services in year t

P_{t-1} = maximum price for group of services year t-1

I = inflation index

X = productivity factor

Z = adjustments for unforeseen events beyond management's control and special one time events

Service quality safeguards are typically required with PBR to ensure that service reliability and quality do not suffer given the incentives to reduce costs.

Some of the pros and cons of Price Caps are shown below.

Pros:

- provides operational efficiency incentives to minimize costs and improve productivity
- shares the benefits of efficiency gains between customers and shareholders

- does not encourage "goldplating" or over investment in capital
- provides incentives to take risks and be innovative
- not as complex, costly and time consuming as Cost of Service regulation
- provides price stability
- provides some pricing flexibility (prices can be lower than the cap)

Cons:

- risk of windfall profits or losses if price caps not set correctly
- cost of service study may still be required to set initial prices if external benchmarks are not available
- cost savings and profits may be pursued at the expense of service quality if there are no service quality safeguards in place
- social & environmental goals which do not increase profits may be less likely to be pursued

1.3 Revenue Caps

Revenue Cap regulation is similar to Price Cap regulation except that revenues rather than prices are capped. Better incentives for a utility to operate efficiently are provided because revenues rather than profits are directly controlled.

Revenue Caps differ from Price Caps in that they reduce the incentives and risks associated with sales (output volume). There is little incentive to increase sales if total revenues are capped. This makes Revenue Caps more compatible with energy efficiency objectives.

Revenue caps are determined by setting initial revenues based on either the utility's existing revenue requirements, an updated Cost of Service study, and external benchmarks from similar utilities. The revenue cap is then fixed for typically three to seven years with suitable adjusts for inflation, growth, and expected productivity improvements. The growth factor is required to adjust revenues for sales growth.

The basic revenue cap formula is shown below.

$$R_t = R_{t-1}(1+(I-X+GAF)) \pm Z$$

where R_t = maximum revenue in year t

R_{t-1} = maximum revenue in year t-1

I = inflation index

X = productivity factor or offset

GAF = growth adjustment factor

Z = adjustments for unforeseen events beyond management's control and special one time events

Service quality safeguards are typically required with PBR to ensure that service reliability and quality do not suffer given the incentives to reduce costs.

Some of the pros and cons of Revenue Caps are shown below.

Pros:

- provides operational efficiency incentives to minimize costs and improve productivity
- shares the benefits of efficiency gains between customers and shareholders
- does not encourage "goldplating" or over investment in capital
- provides incentives to take risks and be innovative
- not as complex, costly and time consuming as Cost of Service regulation
- provides better revenue and financial stability than a Price Cap
- more compatible with energy efficiency objectives than a Price Cap
- provides more pricing flexibility

Cons:

- risk of windfall profits or losses if revenue cap not set correctly
- cost of service study may still be required to set initial revenue requirements if external benchmarks are not available
- cost savings and profits may be pursed at the expense of service quality
- social and environmental goals which do not increase profits may be less likely to be pursued
- unlike a Price Cap, a Revenue Cap requires sales forecast to determine the growth factor

2.0 PBR in Other Jurisdictions

The current worldwide trend towards the use of PBR to regulate utility networks is linked to the introduction of competition and the associated restructuring of the utility industry whether it is electricity, gas, or telecommunications. The form of PBR that is most suitable for use depends upon the type of utility network, and if the industry is being vertically unbundled and restructured in response to competitive forces.

Jurisdictions where competition has been introduced in the electricity industry and PBR has been selected to regulate vertically unbundled electrical transmission companies include England and Wales, Scotland, and Australia. It has also been used in Norway, and California to regulate electrical transmission and distribution which is bundled together. The form and components of the PBR in these jurisdictions are summarized in the table J-1 below.

The preferred form in all jurisdictions where transmission has been unbundled is a Revenue Cap.

Table J-1 PBR for Transmission in Other Jurisdictions

Country & Company	PBR Type	Scope	Duration	X-Factor Offset	Inflation	Z Factor	Service Quality Safeguards
UK National Grid Co	Revenue Cap $R_t = R_{t-1}(1+RPI-X)$, where R=Revenue (additional incentive scheme for losses) (Growth accounted for in calculation of X)	Transmission (new Tx connection excluded)	4 years 1998-2001	4%	RPI (retail price index)	not explicit	planning & operating standards; report on system security, availability, and quality of service
Scotland Scottish Power	Revenue Cap $P_t = P_{t-1}(1+RPI-X)$, where P=average Price/kWh, kWh = predetermined energy delivered, not actual	Transmission (new Tx connection excluded)	5years 1994-1998	1%	RPI		planning & operating standards; report on system security, availability, and quality of service
Australia Victoria PowerNet	Revenue Cap $P_t = P_{t-1}(1+CPI-X)$, where P=avg. Price/kw, kW = predetermined peak demand, not actual	Transmission (new Tx excluded)	5years 1995-2000	1.79%	CPI	tax changes	operating & design standards
Australia (New South Wales) Transgrid	Revenue Cap R={fixed charge*(CPI -X)}+ (energy charge*projected kwh)*(CPI-X)}+ (demand charge*Projected kw)*(CPI-X)}	Transmission	3years 1997-1999	3%	CPI		operating & design standards
Norway Statnett SF	Revenue Cap $R_t = R_{t-1}(1+RPI)(1-X)(1+\Delta kwh/2)$ where R=Revenue, Δkwh = predetermined % growth in energy, true up for actual Δkwh after 5 years	Transmission and Distribution (incl. losses)	5 years 1997-2001	2%	CPI		None but considering: technical standards, reporting failures, penalties for undelivered energy, & contracts specifying quality
USA Southern California Edison	Rate Cap $Rate_t = Rate_{t-1}(1+CPI-X) \pm Z$	Transmission &Distribution (non-generation)	5 years 1997-2001	1.2% 97 1.4% 98 1.6% (99- to 2001)	CPI	Nine criteria for Z factors	financial rewards & penalties for: reliability (duration & frequency), customer satisfaction, and health & safety