3rd Annual Regional Energy Regulatory Conference for Central/Eastern Europe and Eurasia

December 7-9, 1999
Novotel, Budapest, Hungary

Co-hosted by the Hungarian Energy Office

Issue Papers

Tariff/Pricing Committee

- **Procedures for Tariff Reviews and Revisions**
- **Assessing and Incorporating Fixed Assets and Investment Programs into Tariffs**
- **Privatization and Regulatory Control: Integrating the Regulatory Agency into the Overall Regulatory Framework**
- **Technical Losses and Commercial Losses**
- **Cross-subsidies**

Prepared by
Tariff/Pricing Committee

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In consultation with
National Regulatory Research Institute (NRRI)

Facilitated by
Regional Energy Regulatory Program for Central/Eastern Europe and Eurasia,
National Association of Regulatory Utility Commissioners (NARUC)

Sponsored by
US Agency for International Development (USAID)

The publication and distribution of the Issue Papers for the Tariff/Pricing Committee was made possible through support provided by the Energy and Infrastructure Division of the Bureau for Europe and Eurasia under the terms of its Cooperative Agreement with the National Association of Regulatory Utility Commissioners, No. EE-N-00-99-00001-00. The opinions expressed herein are those of the author(s) and do not necessarily reflect the views of the U.S. Agency for International Development.

3^{rd} Annual Regional Energy Regulatory Conference for Central/Eastern Europe and Eurasia

Procedures for Tariff Reviews and Revisions

December 1999

Tariff/Pricing Committee Member Countries:

Armenia, Estonia, Georgia, Hungary, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, Moldova, Poland, Romania, Russian Federation, and Ukraine

Procedures for Tariff Reviews and Revisions

Introduction

A major task for the independent regulatory agencies in Central and Eastern Europe and the Newly Independent States (CEE/NIS) is to implement procedures for tariff reviews and revisions.[1] These procedures will play a critical role in establishing tariffs compatible with the goals set out by new legislation and other reform mandates.[2] In Lithuania, Armenia, and many of the other CEE/NIS countries, for example, the policy of the government is to have utility tariffs correspond to costs.

This paper will discuss attributes of good regulation.[3] These attributes include guidelines for reviewing and revising tariffs, methods for collecting information, the kind of information required for setting tariffs, and features of regulation such as agency transparency and independence.

Guidelines for Reviewing and Revising Tariffs

Generally acceptable tariffs require that certain conditions be met. First, tariffs should protect consumers against excessive discriminatory pricing. This means that price differentials across consumers can be socially desirable when they account for differences in cost and demand conditions.[4] They should, however, satisfy the condition that at the minimum they should cover a utility's cost of service at short-run marginal or incremental costs.[5]

Second, tariffs should allow a utility to maintain financial integrity. One critical requirement for this condition is to allow a utility to earn a rate of return commensurate with its cost of capital. Cost of capital measures a utility's weighted average costs of debt and equity. Financial theory predicts that a utility, perceived by prospective investors to have higher risk, would have to earn a higher rate of return to attract new capital. In an environment of hyperinflation or where specific cost elements for a utility encounter high inflation, some escalation or automatic adjustment factor may be required. For example, price cap adjustment based on a semi-annual inflation index may be required to avoid financial catastrophe for a regulated utility.

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[1] The procedures or processes available to regulatory agencies in reviewing and revising tariffs include tariff proceedings (applications, which may be suspended during an investigation), generic proceedings, rulemakings, public hearings, workshops and other information-gathering forums, investigations, and inter-agency interactions.

[2] In some countries, such as Hungary, the regulatory agency acts only as an advisor on tariff issues, with another branch of government, the Energy Office, having "decision" authority.

[3] Regulation includes the responsibility for setting tariffs. In some countries the regulated entity is privately owned while in others it is a state-owned enterprise.

[4] Price differentiation, *per* se, may therefore not be undesirable. For example, situations exist where price differentiation may reduce surplus capacity, improve the utilization of existing capacity, accommodate competitive conditions (it may be necessary for a utility to compete in certain markets), and boost a utility's profits through increased sales to price-responsive consumers. In the U.S., price differentiation is regarded as appropriate when reflecting differences in cost and demand conditions across classes of consumers.

[5] This is the standard that U.S. regulators generally follow.

Third, tariffs should protect consumers against what can be called imprudent or excessive costs. These costs reflect poor decisions on the part of utility management or improper shifting of costs from non-regulated activities to the regulated entity. Evaluating a utility's decisions should be done on the basis of *information accessible to management at the time* such decisions were made.[6] Management audits and statistical analysis, or in the case where a utility conducts non-regulated activities, cost-allocation reviews, are methods for uncovering imprudent activities.[7] When imprudent costs are identified and measured, the pertinent questions become in what way and how much a utility should be penalized.[8] One approach, commonly used under rate-of-return regulation, is to exclude imprudent costs from a utility's cost of service or revenue requirement.[9]

Fourth, tariffs should assure safe and reliable utility service. In most parts of the CEE/NIS regions, tariffs were historically set too low, leading utilities to underspend in energy-system maintenance and replacement facilities. The aftermath has been deficient capacity and inefficient operation causing unreliable and, in some cases, unsafe utility systems.

Fifth, tariffs should encourage the entry of *efficien*t energy service providers. For example, an excessively low tariff would discourage new entrants to compete with the incumbent utility, even when these entrants are able to produce electricity at a lower cost.

Sixth, tariffs should promote pre-designated goals. For example, a country may have the objective of using electricity tariffs to advance energy development, energy conservation, economic efficiency and equity. Caution should be taken, however, in relying on utility tariffs as a funding source for advancing certain national-interest objectives since as a commercial enterprise, utilities should be financially self-sufficient. In part, this means that pricing policies for utility services should correspond to those of non-regulated commercial enterprises.

A second and often principal objective, which a country may seek to advance through its energy tariffs, is the attraction of investment needed to improve the assurance of a sufficient and reasonable-cost energy supply for its citizens. Such investment, while adding an additional cost to rates because of the need to permit recovery of its cost, may actually reduce, either immediately or over time, rate levels by permitting construction or rehabilitation of lower cost energy production or transmission facilities. The principles which need to be applied and available tariff forms which can lead to achievement of this

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[6] Evaluating the prudence of a utility's costs based on a retrospective or after-the-fact review using perfect hindsight is improper. Such a review focuses more on outcomes rather than the process applied by utility management in making decisions.

[7] A statistical analysis, for example, can help to uncover whether a particular utility's costs are out of line with the costs of comparable utilities.

[8] Answers to these questions depend largely on the legislative authority granted a regulatory agency.

[9] Cost of service and revenue requirement are synonymous terms referring to the costs required by a utility to provide energy service to consumers. These costs include operating and maintenance expenses and cost of capital.

objectives are set forth in a separate paper prepared for the Committee entitled "Assessing

and Incorporating Fixed Assets and Investment Programs into Tariffs."

Another issue centers on the authority of different groups to propose and initiate a tariff review and revision. A distinction should be made here between the terms "review" and "revision." A review, for example, may entail examining current tariffs to assess whether they are compatible with the objectives of new legislation and other reform mandates. In contrast, a revision includes the act of changing tariffs, which of course may be the outcome of a tariff review.

Who can prepare or initiate a tariff review and revision has important implications for agency transparency. Assume, for example, the regulated entity is the only party that can propose a tariff revision. The regulatory agency then lacks the discretion to revise current tariffs, which may serve the interest of the regulated utility but not the public interest. Depriving non-utility interest groups of the right to propose a tariff review or revision may create the public perception of an unfair and non-independent regulatory agency.

Regulators, of course, may not revise tariffs arbitrarily to the injury of either investors or customers. The statutes creating the regulatory agency and defining its jurisdiction establish standards upon the basis of which rate levels must be established, whether the consideration of new rates are requested by the energy provider, ratepayers, or the commission. Moreover, the agency's determination that a particular rate level satisfies these standards is typically subject to review by an independent, judicial appeals court.

Crucial Information for Setting Tariffs

Price regulation requires the regulatory agencies in the CEE/NIS countries to compile a variety of information. This information is needed to establish tariffs that follow the guidelines previously discussed in this paper. Certain of the CEE/NIS countries are currently handicapped by the unavailability of detailed cost data, financial information, and technical information on their electric and natural gas sectors. Consequently, during the next few years regulatory reporting and procedures will need to be defined and implemented.

New legislation in many of the CEE/NIS countries requires regulatory agencies to promote universal, high-quality service at reasonable prices. Under this mandate, a regulatory agency should allow regulatory entities to earn adequate returns to attract new capital and to ensure efficient operation; this may require the gradual reduction of cross-subsidies, which in turn requires measuring the costs ("revenue requirement") of utility services, in addition to revenues collected under different tariff scenarios (e.g., current tariff, "gradual reduction and removal of measurable cross-subsidy" tariff).

Under U.S.-type regulation, which is being implemented in some of the CEE/NIS countries, the overall level of prices is determined by what is called the *revenue* *requirement* — the total revenues the utility is allowed to recover from consumers in order to recover costs. This method is referred to as determining the "cost of service."

Under rate-of-return regulation, the utility's revenue requirement is calculated as

Revenue Requirement = Operating and Maintenance Expense + Depreciation Expense + Tax Expense + Allowed Rate of Return × Rate Base.

Each component of the revenue requirement must be calculated. Even under a price-cap method, a revenue-requirement calculation is required to derive the starting prices from which periodic allowable price changes are added.

An important parameter of the revenue requirement equation is the allowed rate of return. Under general regulatory practice, the allowed rate of return corresponds to a utility's cost of capital, accounting for both country risk and commercial risk.

The second step in setting tariffs is to assign responsibility for revenue recovery. This involves spreading the revenue requirement among the various customer classes and services that the utility sells. As recognized by practitioners throughout the world, cost allocation is as much an art as a science. Many methods of cost allocation exist, all encumbered by the existence of what are called common or joint costs.[10]

The third step in setting tariffs, rate design, involves developing the actual prices charged to consumers. These prices should be compatible with the objectives of regulation as established by the legislature, the central government or the regulatory agency itself. For example, these objectives may include economic efficiency and equity. Several rate design possibilities exist — e.g., two-part tariffs, non-uniform rates, seasonal and time-of-use rates — each with a distinctive underlying philosophy and outcome.[11] Seasonal and time-of-use rates, for example, are based on marginal-cost principles recognizing differences in a utility's costs across seasons and time of day.

In addition to cost and revenue data, a regulatory agency should have additional information to assess the overall performance of regulated entities. For example, the number and nature of consumer complaints, the level of service reliability, and the magnitude of technical and commercial losses are all indicators of a utility's performance. In carrying out its responsibility, a regulatory agency should take the initiative in monitoring and assessing a utility's performance in various areas as it related to the public interest. If, for example, the agency concludes that consumer complaints are excessive and caused by utility negligence, it should take appropriate remedial action.

[10] By definition, these costs cannot be unambiguously assigned to a particular customer or service.

[11] A two-part tariff, for example, helps to advance economic efficiency and to lower a utility's risks. Under this tariff structure, a consumer would, at the margin, pay an energy charge corresponding to short-run marginal cost and the utility would recover its fixed costs in a customer charge or demand charge, or both. A lower usage or marginal charge has four benefits: (1) it allows a utility more flexibility in competing, (2) it induces more sales or higher throughput, (3) it promotes allocative efficiency by moving the marginal price toward marginal cost, and (4) it reduces risks to a utility.

Guidelines for Successful Regulation

To be successful, regulatory agencies in the CEE/NIS countries must advance the

public interest. One indicator of success, taken from economics, can be measured by the net benefits (i.e., benefits minus costs) of a regulatory agency's actions to the citizenry. The justification for public utility regulation is premised on the existence of market deficiencies or failures to produce socially desirable outcomes. Consequently, a major task of regulatory agencies is to "correct" for these deficiencies through their tariff policies in addition to other policies. Tariff policies, consistent with addressing the market failures of an otherwise unregulated utility sector, include those that attempt to promote economic efficiency or environmental objectives.

Successful regulation will produce adequate, reliable and least-cost energy service in an environmentally acceptable manner. Under such regulation, a regulatory agency possesses certain traits that are recognized universally by experts and practitioners as essential; these traits are viewed as inherent for achieving success in serving the public interest. The major ones include:

(1) reasonable and fair balancing of the various legitimate interests,[12]
(2) up-front regulatory rules and guiding principles,[13]
(3) responsiveness to consumer complaints,[14]
(4) avoidance of short-term politically-driven decisions,
(5) transparent decision making,[15]
(6) accountability,[16]
(7) effective information gathering and dissemination,[17]
(8) a competent staff,[18] and
(9) a pro-active agency posture.[19]

Some of these attributes are particularly important for the regulatory agencies in the CEE/NIS countries. The Hungarian Energy Office expressed the significance of an open-participation process to achieve agency transparency. Transparency refers to the general public having the opportunity to actively participate, if it so desires, in the regulatory process. Consequently, transparency can result in utility consumers and

[12] One interpretation would be to balance the general public's interest with the right of a utility to conduct business in a way that allows it the opportunity to be financially sound.

[13] Such rules and principles would provide more predictability of a regulatory agency's actions to the capital markets and utilities.

[14] These complaints can result from a utility's operating practices, the failure of a utility to negotiate in good faith, billing disputes, and safety concerns.

[15] As discussed below, transparency increases public credibility and legitimacy of the regulatory agency.

[16] This feature requires that an agency's decisions are subject to court appeals or some other independent forum.

[17] This involves collecting relevant information, analyzing that information, and synthesizing the analytical results into decision options.

[18] The problem of recruiting and retaining good staff personnel can be a serious one.

[19] This involves the agency exercising oversight of and, when appropriate, direction to a public utility's activities.

investors feeling that they have been treated fairly. The reason for this is that an open process helps to prevent one group from unduly dominating a regulatory agency's decisions.

In Ukraine, transparency is being achieved by announcing commission hearing

decisions including tariff reviews in the media. The newspapers also publish on a monthly basis information on energy suppliers' prices. Transparency may entail the regulatory agency educating the legislative and non-governmental organizations on how tariffs are set and why tariff increases may be justified under the cost-of-service criterion.

Agency independence is an important attribute of successful regulation. "Interference" with an agency's decisions can come from various sources — namely, the regulated utilities, the executive branch of government, the legislature, special interest groups, and the judicial branch of government. Like agency transparency, the independence of a regulatory agency can increase its credibility with the different parties as well as the general public. Independence can be best achieved by an agency's balancing of the different interests and by decisions based primarily on the information provided by the various interests in an open forum. In a tariff review, it may be important for the regulatory agency to implement independent-control mechanisms which fit within the existing legal framework but, at the same time, allow the agency to implement an independent tariff policy balancing the interests of utilities and consumers.

Accountability and efficiency are also important features of a well-operating regulatory agency. Accountability can be advanced by allowing for open participation of interested parties in tariff proceedings and other matters under consideration by the regulatory agency. Accountability may also require publication of agency decisions and the rationale for those decisions, and a performance audit of the agency by an oversight committee of the legislature or another branch of government.

The essence of agency efficiency is the ability of an agency to make decisions in a reasonable timeframe. Such an outcome usually requires and indeed results from little or no intrusion by the other branches of government. One goal of regulation should be to prevent a regulated entity from expending large amounts of money and management resources on litigation and excessive regulatory procedural requirements. Utility consumers would benefit by not having to pay for the high "regulatory costs" that would otherwise be imposed upon the regulated entities.

One issue associated with effective information gathering by a regulatory agency centers on the agency's authority to require information, even confidential information, from a regulated utility. The National Energy Regulatory Agency of Moldova has wide discretion to obtain such information. The agency even has the authority to revoke a utility's license if the utility fails to respond to an information request. Other regulatory agencies in the CEE/NIS countries are reviewing their reporting and implementation authority. They are also defining and implementing approaches for data-collection systems.

Synopsis of Committee Discussion

During the Yerevan meeting, representatives of the independent regulatory agencies in the CEE/NIS countries discussed principally the importance of agency transparency for successful regulation. With transparency, the public recognizes the process is fair and accepts the results, even when tariffs increase. In the United States,

state commissions give priority to achieving transparency in their decision making. Notice is provided in newspapers, with direct mailed notice to known interested parties, for a tariff review and/or revision filing. The detailed cost data together with supporting financial and technical information necessary to conduct the tariff review or revision is made available to all parties. Public hearings are held, often with regional hearings, and with parties and citizens permitted to submit testimony. Those who are formal (interested) parties are also permitted an opportunity to question the accuracy and veracity (cross-examine) of the testimony of other parties. All decisions are in writing, supported by findings of fact and reasoning.

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Assessing and Incorporating Fixed Assets and Investment Programs into Tariffs

December 1999

Tariff/Pricing Committee Member Countries:

Armenia, Estonia, Georgia, Hungary, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, Moldova, Poland, Romania, Russian Federation, and Ukraine

Assessing and Incorporating Fixed Assets and Investment Programs into Tariffs

Background

Electricity and natural gas assets in the CEE/NIS countries are presently or were formerly owned typically by the government, either directly or through ownership of joint stock companies. As a result, records as to the original cost of those assets were not developed upon the basis of International Accounting Standards. This makes assessing the value of those fixed assets difficult. These difficulties are compounded by the fact that existing capacity of electric generation and of electric and gas transmission and distribution systems are generally larger than current demand in CEE/NIS countries. As a result, rate levels, which would exceed affordable levels, may be required under traditional cost-of-service regulatory principles to support fully the book cost of such plant. Yet, much of the existing electric and gas plant is obsolete or in need of repair. There is thus also a need for additional investment to rehabilitate and improve the efficiency and/or to reduce the costs of operating such systems. Electric and natural gas assets, including entire operating systems, are being offered for sale to strategic private investors to obtain the investment capital needed for rehabilitation and efficiency improvements. A mechanism is needed to reflect the cost of these investment programs in rates.

Valuing and Incorporating Existing Fixed Assets into Tariffs

Because the original cost of assets were not developed upon the basis of International Accounting Standards, original cost valuation may not be a practical or practicable method for valuing the cost of construction for purposes of incorporating existing assets into tariffs. Instead, an alternative form of valuation might be appropriate.

One promising alternative might be to use the acquisition costs of assets (including any debt assumed by the private investor) which have been purchased as a means of assessing their value. If there are several potential buyers of plants or operating systems, the final acquisition cost of the assets could reflect their market value at the time of acquisition. In the absence of reliable original cost accounting, such an acquisition cost would be a superior method of valuing fixed assets for the purpose of incorporating them into tariffs.

In addition, it may also be appropriate to reflect capital provided for purposes of rehabilitation in rate base. Even if such capital was donated so that it might require no return, there is still a vital need to place the capital in rate base so that it can be depreciated and so that maintenance expenses can be fully recovered. If depreciation and maintenance expenses are not provided in rates, there will be no incentive to invest in order to rehabilitate plant, and any investments that are made will deteriorate. If capital for rehabilitation had a cost to an investor who “donated” it, then it should also receive a return on the capital in order to encourage further capital expenditures for rehabilitation.

In the United States, traditionally, plant must be both used-and-useful to be incorporated into rate base and hence into tariffs. Under the used and useful valuation

method, one reason to remove an existing asset from rate base is that it represents excess or over-capacity and is not used or useful for either energy or reliability purposes. Some portion of the plant is considered used and useful, however, if it is needed to satisfy the targeted reserve margin.

In the United States, when a plant represented excess capacity, there was sometimes a regulatory provision that allowed a phase-in. A plant could be phased into rate base either according to a set schedule (typically not to exceed five years) or as demand grew and the plant became needed. Some United States regulatory entities do not totally exclude a plant that is not used and useful from rate base. Instead, they allow a depreciation allowance on the plant and they often allow for a return on the debt portion of the cost of capital, even though no recovery is allowed on the equity portion of the capital. This approach is used in a majority of American state commissions.

However, it is important to understand that past United States excess capacity occurred in a different political, economic, and investment environment than excess capacity concerns of CEE/NIS countries. The United States excess capacity issues and concerns relate to problems of demand growth decreasing from previous projections, bringing large and expensive, *newly completed* plants into service before they were fully needed, and the "rate shock" effect that immediately including those plants into rates would have.

The CEE/NIS excess capacity concerns deal with how to permit cost recovery on *existing fixed plant* that was built to serve demand greater than present load. For example, the representative from Lithuania stated that their fixed assets could serve three to four times the present load. Therefore, different solutions might be appropriate for the excess capacity being experienced by the CEE/NIS countries.

When considering the use of the used-and-useful valuation method, there should not be a used-and-useful valuation adjustment made for excess capacity done subsequent to valuation done through the acquisition of assets purchased competitively. In such cases, plant that is not used and useful has already been discounted in the acquisition price.

The used-and-useful valuation method could provide a justification, though, to have temporary reductions in fixed-asset valuation based on the number of service or outage complaints. In spite of excess capacity of fixed assets, utility service may not meet acceptable levels of reliability in terms of the frequency and duration of outages, the quality of power or delivered energy services, and in terms of connection, metering, billing, and collection services. CEE/NIS regulators might consider providing penalties and incentives to improve utility performance in these areas.

Assessing and Incorporating Investment Programs into Tariffs

Private entities may reinvest in and rehabilitate an existing plant that would not otherwise be used and useful; and, for a variety of reasons, private entities may be willing to invest in and build new plant to achieve service reliability and economy, though

adequate (and perhaps even excess) existing capacity arguably already exists. Private entities might undertake such investment because new plant and refurbished existing plant may be more efficient and have a lower cost (both operating and capital), and almost certainly have a lower operating cost, than existing plant. Since this new plant may be more efficient and more reliable than existing plant, many countries might wish to encourage such investment. And, if such new or rehabilitated plant is more efficient than existing plant, then the new or rehabilitated plant would be consider to be used and useful.

Multi-year rate formulae can encourage investment in new plant or investment to rehabilitate or refurbish existing plant. Indeed, long-term rate design, when tied to investment programs, will stimulate the inflow of long-term investments, and at the same time, provide approved rates that are predictable. The concept of a multi-year rate formulae is that the commission provides for long-term rate design that makes rate increases predictable and not subject to unexpected changes. This is done by means of rate formulae that lasts for several years, but not indefinitely. Such a formula can stimulate investment indirectly by providing certainty to investors; or, such a formula could directly stimulate investment by directly requiring levels of investment or by requiring, for example, pre-set levels of reliability.

One example of how a long-term rate agreement would work would be the Telasi distribution system's privatization and long-term rate agreement that was approved and agreed to by the Georgia National Electricity Regulatory Commission (GNERC). The agreement provides for a gradual increase of the electricity distribution tariff during the next four years and during the longer term of ten years. Tariff increases are tied to promised investments of approximately $84 million being made over the ten-year period in accordance with the agreement. Such a multi-year license-based rate formula can be a particularly effective way of encouraging new investment as both rate increases and continued possession of the license can be tied to fulfilling investment commitments.

There has also been experience with long-term rates in Hungary. According to the representative of the Hungarian Energy Office, all utilities were re-valued on the basis of acquisition costs during privatization. Later, in 1997, the Commission incorporated an inflation index that was based on 1996 inflation rates into the tariff. The current mechanism is in place until the Year 2000, after which there will be a new mechanism. The problem has been that it complicates movement toward more competitive arrangements.

There are also several examples of multi-year rate formulae that can encourage investment that have been used in the United States. Both the New York Public Service Commission and the California Public Utilities Commission have multi-year rate cases so that approved rates are both predictable and stable. The New York Commission typically does three-year settlements of rate cases, which sets a three-year rate plan. In some of its three-year rate settlements, the New York Commission has approved revenue adjustment mechanisms which provide for automatic rate adjustments if a utility's actual revenues fall below the projected level due to a shortfall of sales. California also does multi-year (two year) rate cases, sometime with similar revenue adjustment mechanism for under- or over-collection of revenues due to actual sales varying from projections.

An additional example of multi-year rate formulae is a price cap formula. Price caps have several advantages over traditional rate-of-return regulation. For example, the utility has a stronger incentive under price caps to be cost-efficient, particularly if large investments were to lead to immediate productivity gains and cost savings that under traditional regulation would be entirely flowed through to customers. Price caps generally start with existing rates, adding an escalator clause based on some general price inflation, subtracting out then an annual percentage reduction for expected savings from innovation and economies. In many instances in the United States, price caps are coupled with profit-sharing mechanisms to share with ratepayers part of the increased productivity of the utility.

Another example that is somewhat different is the State of Alabama Rate Stabilization Equalizer which provides for automatic rate adjustments that are triggered by the realized rate of return. Here is how it works. The Alabama Public Service Commission allows the rate of return on common equity and the revenue requirement to fluctuate within a limited range set by the Commission. In turn, the utility adjusts its rates on a quarterly basis so that it will earn the common equity return that is the mid-point of the range.

From April 1975 to early 1982, the New Mexico Public Service Commission used a cost-of-service index for quarterly adjustments of the electric rates of its major utility. The index was initially adopted because of high inflation and a high rate of demand growth. This is how it worked in practice, the company submitted its actual costs and revenues for the year ending with the most recent quarter. It then recalculates its revenues as if the last quarter's index had been in effect for the full year. The cost-of-service index, a rate surcharge, would then be calculated and rates adjusted upward if the utility's rate of return on equity fell more than one-half percent below its allowed rate of return on equity. This left the company with a limited incentive to control costs.

A method different than the New Mexico cost-of-service index might be better suited for encouraging investment and efficiency improvements. For example, rate-of-return increases or margins over cost might be directly tied to meeting investment goals and improving the efficiency and reliability of the system. Alternatively, multi-year price caps or performance-based rates could be tied to specifically set out goals being met. The goals to be met could concern, for example, customer service levels, power plant performance, hours of service, capacity availability, line loss levels, and/or outage levels.

One special problem and concern is providing a mechanism for recovery of nuclear decommissioning costs. A first principle of dealing with decommissioning funds is that, to the extent practicable, those who benefit from the generation of nuclear power should pay for the cost of decommissioning the plant. Therefore, a charge of decommissioning should be included in current customer rates in service areas where there is generation from nuclear power. There are many possible regulatory treatments of decommissioning funds, each with different costs, different revenue risks, and different risks of inadequate financing. The current preferred method used in the United States is the use of an external nuclear decommissioning trust fund coupled with insurance to minimize the risk of inadequate financing in the event of premature decommissioning or

utility insolvency. Internal trust funds or other internal decommissioning funds might have the advantage of providing a source of investment funding for other utility improvements, but have the disadvantage of increasing the risk of inadequate financing being available at the time of decommissioning.

Investment in new plant and/or reinvestment in existing plant can be encouraged by allowing costs of construction work in progress in rate base and tariffs, as construction is taking place. Another possibility would be to provide for a future expense allowance for non-rate-based capital costs as they occur. However, before allowing any such new plant or refurbished existing plant investment into rate base, the regulatory agency might review the investment planning of the private utility to assess its reasonableness.

The representative from the Ukraine National Energy Regulatory Commission observes that many of the proposals, including the inclusion of repair funds in rate base and the inclusion of under construction investment projects may be impossible under their existing Ukraine legislative framework. The issue of inclusion of future investment in current rates remains open for some CEE/NIS countries. Including such investment in current rates would encourage private investment that would rehabilitate or expand electric facilities. But for such methods to succeed, regulatory bodies need measures that would ensure transparency of the regulatory policies with regard to the investment.

The Special Problem of Social Programs and Regulatory Assets

One special problem is that in some CEE/NIS countries there are non-utility related expenditures that are still carried on the books as a part of the cost of service. Non-utility-related expenditures, including non-utility-related social programs, are not considered to be used and useful in the production of utility service and are not normally included in rate base and are, hence, not reflected in rates. Examples of such non-utility-related expenditures would include items such as day care centers, retirement homes, and health spas, for example.

The expense of utility-related social programs is only included in rate base as a regulatory asset if the expenditure was done at the mandate of the government; otherwise, it is excluded from rates. When utility-related social programs are included in rates, they are sometimes identified as a separate line item on the bill. Such expenditures could include nuclear safety and decommissioning funds, low-income programs to make electricity affordable, conservation programs, and other social programs.

Even so, it is considered preferable by the investment community and a matter of good government to provide for social costs directly out of the government budget. Over-reliance on utility rates to recover the costs of social programs will discourage needed foreign and domestic investment. Several CEE/NIS countries have or are now taking steps to transfer such costs to government budgets. For example, it has been reported that Ukraine utility social spending costs are rather low today because most social sites and organizations that were funded by rates have already been transferred to the balance sheets of local municipal councils. Such gradual transfer is mandated by current legislation. Investors view such actions positively. Further, there are also economic

efficiency concerns that result from social costs being included in rates, including possible inefficient allocation of resources and the under-consumption of utility services.

Synopsis of Committee Discussion

The CEE/NIS country delegates discussed specific fixed asset related tariff and rate issues in connection with this paper in Yerevan, including the necessity of planning for and providing a funding mechanism for nuclear power plant retirement, thermal power plant retirement costs, the need to provide rate mechanisms to attract investment for replacement capacity, the importance of properly reflecting operation and maintenance and depreciation expenses in rates, and procedures for gradualism in tariff revisions.

In the United States, monies are collected for the retirement of nuclear power plants during the period that the plants are in operation. In contrast to the retirement of thermal power plants, the retirement of nuclear power plants has a negative net salvage value. The net salvage value of a plant is the plant's salvage value minus the cost of retiring the plant minus any undepreciated book value of the plant upon retirement. Unless a thermal power plant is retired before the end of its expected useful life, it almost always has a positive net salvage value. As such, no special provisions are typically made in United States utility regulation to recover the cost of retiring thermal power plants. All that needs to be done, in the case of thermal power plants, is to make certain that the depreciation allowance in rates is sufficient so that at the end of the plant's useful life, the salvage value of the plant will pay for its dismantling.

In the case of a nuclear power plant, however, the net salvage value upon retirement is almost always negative, because the cost of safely decommissioning and retiring a nuclear power plant far exceeds the salvage value of the plant. The size of the negative net salvage value increases when the nuclear power plant prematurely is retired or shut-down before the end of its planned useful life. A first principle in United States utility regulation is that those who benefit should bear the costs. As such, through one of two major mechanisms, all state commissions allow for the recovery of future nuclear power plant decommissioning expenses in current rates while the plant is still operating. The additional amount allowed in rates is typically set at the net present value of the expected negative net salvage value of the nuclear power plant. These monies are then collected either through a surcharge on energy or, more commonly, an addition to the depreciation allowance. Two-thirds of the state commissions with nuclear power plants require that monies collected for nuclear decommissioning be set aside in an external trust fund, while the remaining third allows the utility to reinvest the funds internally in its own plant. Both methods of dealing with nuclear power plant decommissioning funding are allowed to the extent that nuclear power plants are whole sale in nature, and hence, under the jurisdiction of the Federal Energy Regulatory Commission.

There was also discussion concerning the importance of providing sufficient depreciation allowances for replacement of capital as well as the importance of properly reflecting operation and maintenance as well as depreciation expenses in rates. Without adequate depreciation allowances and proper operation and maintenance expenses being included in rates, private investors will tend to allow existing plants to become obsolete or

deteriorate.

Finally, the delegates discussed the need for procedures to soften the impact of large rate increases on the general public. In the United States in the past, rate increases have sometimes been phased into rates according to a set schedule that is relatively short, for example, often two or three years, but never more than five years. During the phase-in period, however, the time value of the unrecovered capital continues to grow. Ultimately, it is recovered in rates. Thus, while rate phase-ins might make rate increases gradual, ultimately, they result in higher rates.

3rd Annual Regional Energy Regulatory Conference for Central/Eastern Europe and Eurasia

Privatization and Regulatory Control: Integrating the Regulatory Agency into the Overall Regulatory Framework

December 1999

Tariff/Pricing Committee Member Countries:

Armenia, Estonia, Georgia, Hungary, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, Moldova, Poland, Romania, Russian Federation, and Ukraine

Privatization and Regulatory Control: Integrating the Regulatory Agency into the Overall Regulatory Framework

Background

Power sector privatization has been undertaken or is planned in many of the CEE/NIS countries. For example, the privatization process within the electricity sector in Georgia started in 1994. Since that time twenty-one small hydro-generation plants have been privatized. The privatization process in Georgia has been and is being carried out by the Ministry of State Property Management. To implement the privatization the Ministry of State Property Management set up a Tender Committee in 1997, of which the Minister of State Property Management is Chairman. Other members of the Tender Committee include the Minister of Finance, the Minister of the Economy, the Minister of Fuel and Energy, the Minister of Foreign Economic Relations, the Minister of the Environment, the Minister of Agriculture, and Chairmen of the Parliamentary Committees of Sectoral Economy and the Committee of Reforms. In April 1998, privatization of the electricity sector was expanded and the Chairman of the Georgian National Electricity Regulatory Commission (GNERC) was made a member of the Permanent Tender Committee for the Privatization of the Major Electricity Enterprises.

By the time the chairman of the GNERC was included on the Tender Committee, the Georgian government had already selected the investment bank Merrill Lynch as the consultant for privatization issues in the electricity sector. Terms of the tender offer of the Tbilisi distribution company (Telasi) had been announced and potential future investors had been identified. Consequently, the GNERC did not officially participate in the development of the terms of the tender. Nevertheless, the GNERC had several meetings with representatives of the Ministry of State Property Management, Merrill Lynch, and the future investors on retailing, licensing, and other regulatory issues.

On October 20, 1998, the winner of the tender was announced: "AES Silk Road Holdings" (AES). On December 22, 1998, the Telasi distribution company was privatized with 75 percent of the Telasi stock being sold to AES. The GNERC actively participated in this process, where required to discharge its statutory responsibility. Specifically, the GNERC required and received information from Merrill Lynch as well as from the Ministry of State Property Management. An important part of the privatization agreement with Telasi involved a gradual increase in the distribution margin in the electricity tariff in exchange for investments in the system scheduled to take place over a longer period (ten years). The ten-year agreement also adjusted prices based on inflation and fluctuations in the exchange rate. The GNERC considered the calculations that were submitted supporting this agreement, and based on the investment schedule, agreed to and approved the rate and service terms for AES.

In Hungary, privatization of five of six thermal plants and all six distribution companies was substantially completed by 1996. The Hungarian Energy Office was asked by the Minister of Privatization to aid in the preparatory phases of privatization by

preparing detailed regulations, including pricing method and licensing procedure, to be used for existing and newly privatized plants, by preparing to issue licenses to privatized entities, and by developing grid rules and business codes of conduct.

The Hungarian Energy Office (HEO) was also involved in the privatization process as required by its responsibilities. The HEO commented on all privatization-related papers given to potential investors, met with potential investors, and provided the financial and legal advisors of potential investors with a detailed regulatory view of future activities. During the privatization process, the HEO evaluated potential investors' business plans, controlled pre-qualification, participated on the selection committee, and approved share transfers. The Minister set prices, based on the recommendations of the HEO. Electricity prices in Hungary are established on a national basis, and not on the basis of individual company costs. Each element of electricity prices is calculated by the HEO. The HEO method is based on a rate-of-return-type of regulation to determine an average starting price that has been subsequently adjusted by a price-cap-like formula that takes into account inflation, the foreign exchange rate, oil price indices, and authority-controlled gas prices. A profit-cost sharing mechanism is employed.

In Ukraine, privatization of enterprises is being handled by the State Property Fund. During privatization of the electricity sector, the Ukraine National Energy Regulatory Commission, in accordance with the Law of Ukraine on Electric Power, reviews purchases of more than 25 percent of shares, or foreclosures on more than 25 percent of the assets of enterprises. Thus far, seven distribution companies have been privatized, with 50 percent of the ownership going to private entities, some to workers, and the rest to the state. Privatization was carried out on a piecemeal basis (5 to 10 percent of the share ownership at a time) until 51 percent was owned by other entities. A Presidential Decree issued on August 2, 1999 calls for sales of nineteen distribution companies through competitive tenders to experienced power companies (i.e., strategic investors).

Privatization efforts have been undertaken in Poland and Moldova. The privatization process in Poland falls under the Council of Ministers, with the Minister of the Treasury having the legal authority and obligation to prepare yearly programs of privatization of state-owned assets and to manage those programs approved by the Council. The Regulator has played a supportive but background role in the Polish privatization process. The Regulator has been made a member of a working group of the Economic Committee of the Council of Ministers. This working group has the task of completing preparations for the establishment of a Power Exchange in Poland. The Regulator in Poland faces special problems in achieving power market development because of pre-existing long-term energy contracts for the delivery of electricity. Although these contracts have facilitated financing in rehabilitation of equipment, they have complicated the development of competitive markets.

Moldova established the legal framework and set up the National Energy Regulatory Agency prior to the privatization process. As such, all issues affecting tariffs require the prior approval of the regulatory agency. Indeed, prospective rates and tariffs were approved before the privatization process. All distribution ownership (100 percent)

is being privatized and at least 51 percent of all generation ownership is being privatized.

Privatization has, in some other situations, occurred without the involvement of the regulatory agency. In some countries, an agency such as a Department of Privatization or a Minister of Energy, has privatized utility assets either by selling off the generation plant or by selling off the distribution companies, or both, without regulatory involvement or approval. (Sometimes the regulatory agency did not yet exist as was the case of the Kazakhstan agency.) The agency that enters into such a privatization agreement might enter into contracts that specify, among other things:

(1) rates, either general or specific;
(2) guaranteed rates of return or guaranteed margins;
(3) long-term performance-based or price-cap formulas;
(4) guaranteed take-or-pay provisions;
(5) cash payments to the government, coupled with guarantees that the new owner would provide new investment if rates or margins are established at a particular level;
(6) and/or the new owner would pay off international loans on the generation or distribution plant.

The undesirable result of such an approach is that a long-term arrangement affecting customer rates and services has been put into place without any regulatory agency involvement or even an opportunity by the agency to review the proposal for reasonableness and customer protection before its approval.

Privatization Issues Addressed by Regulators

Regulators of Georgia, Hungary, Ukraine, Poland, and Moldova have addressed a number of issues associated with privatization. For example, long-term rate and contract investment matters raise a number of concerns. Long-term rate and contract investment provisions are often essential to attract investors who are willing to make investments that raise the efficiency and lower the cost of the electricity system. An investor requires reasonable assurances that it will receive a fair return on its investments, which can be provided through a long-term rate mechanism, while regulators need assurance that investments that increase supply or reduce costs will be or have been made prior to authorizing rate levels which recover those investments. Entering into such long-term contract arrangements, however, might lead to prices being locked-in over a long period, which might tend to stifle the development of more dynamic and competitive electricity markets. As the regulators from Poland noted, there is a concern that long-term contracts might interfere with the establishment of a Power Exchange. Specifically, the consequences of long-term contracts can be that most energy is sold pursuant to the long-term contract and very little energy is available to trade on the Power Exchange. Further, such long-term contracts might be used to effectively lock-out other future potential entrants into the market. These considerations, of course, do not argue against the adoption of long-term rate and investment terms in privatization agreements, but rather demonstrate the need for their careful consideration. Indeed, it should be noted that the privatization programs for Hungary, Poland, and Georgia all involved a long-term rate-setting mechanism.

Another related concern deals with how privatization should be done as it affects the establishment of the electricity market. More specifically, if all of the generators in a country were sold in multi-unit groups, the generation market for electricity might not be competitive and may even establish a monopoly at the generation level. On the other hand, rather than purchasing a single asset, investors may be more willing to purchase a "bundle" of generation or generation and distribution assets, thereby reducing their costs and investment risk. Obviously, in the initial short-run, especially where there is generation in excess of demand, the more generation owners there are, the more competitive the market might be. Yet, selling the generation plants as a single group might generate the highest or only privatization offer. The Georgian regulators are currently debating whether to group power plants that are to be privatized into two or three packages. A regulatory agency could also harm its country's investment attraction capability if it (1) fails to properly and adequately recognize the need to provide a fair opportunity to investors to earn a return upon investments made to rehabilitate or expand energy system assets, and (2) fails to establish transparent and predictable methods of tariff determination and participation in the privatization process.

In addition, there are specific concerns about problems that can arise from the cross-ownership of generation and distribution. The problems relate to the possibility that distribution companies might favor their own generation and thus weaken the competitiveness of the market. Cross-ownership issues were raised as a concern of Georgian and Hungarian regulators. In particular, the Hungarian regulators are concerned that they lack clear rules to avoid re-integration of the utility through cross-ownership. Another issue faced by regulators is the restructuring of debt and the effect that long-term debt restructuring could have on rate levels. For example, in some instances natural gas was purchased to produce electricity or for retail consumer use, and such purchases have created long-term debt backed and secured by electric or natural gas system assets. In order to attract investors, a large part of the debt might need to be restructured. One solution is for the government or a non-privatized, government-owned energy provider to assume a large portion of the debt, while the privatized entity assumes the rest of the debt, which is in turn reflected in rates.

Transparency of Regulator Involvement and the Establishment Cost Recovery Principles

During privatization, it is important for regulatory bodies to be involved in that aspect of the process that affects their regulatory responsibilities. The rights and responsibilities of the new owners of the former government property should be clearly defined to recognize the operation of their asset is subject to the regulator's jurisdiction. Where a regulatory agency reviews privatization terms that are subject to its regulatory authority, the agency may appropriately consider factors in the public and national interest which go beyond traditional rate and regulatory principles. Regulatory bodies' participation in the privatization process should be done in a manner that maintains their autonomy, their authority, and the transparency of regulation. Prior to and during privatization, the rights and responsibilities of the new owner should be clearly defined by law or by contract.

Reasonable assurance of cost recovery is also an underlying principle that must be observed to attract investment. When governmental entities enter into contracts that specify prices, terms, and conditions that are justifiably relied upon by the group making an investment, all governmental agencies should be subject to an estoppel that prevents them from changing the underlying terms of the agreement. In the United States, an estoppel prevents a legal person, including a governmental agency, from acting in a manner that is contrary to a previous position that is justifiably relied on by another. Certainly, when acting contrary to previously agreed-upon arrangements, governmental agencies harm (if not destroy) that country's ability to raise investment in the international community. Denying the new owner a fair and reasonable opportunity to earn a return can harm a country's ability to raise investments as well.

CEE/NIS countries may continue government ownership in transmission and dispatch plant. As part of the process of commercialization, investment decisions made by the governmental agencies should be subject to the review and approval of the regulatory agency. The regulatory agency should also approve all the rates, terms, and conditions of service by the governmental entity.

In most CEE/NIS countries, privatization of both generation and/or distribution companies is occurring now or is expected in the future. Ideally, governmental laws should make clear that all privatization contract terms that deal with prices, terms, and conditions of service should be subject to the review and approval of the regulatory agency. In particular, long-term supply or other contracts affecting customer rates or services should require some form of review and approval by the regulatory agency. Transparency is also important from the investors' point of view: it provides the investor with a sense that there is procedural justice that the investor can rely upon and that gives the investor confidence in the underlying agreements and tariffs involved in the privatization. Put another way, where regulation is transparent the investor knows the rules, for example, the principles upon which rates should be set, and can anticipate how it will be treated in the future. Such privatization contracts present unique opportunities for CEE/NIS countries to secure necessary future investments that can lower commercial and technical losses as well as achieve more reliable energy services.

Contract Review Principles

In the United States, long-term supply and other contracts, which affect jurisdictional rates, would be subject to one of three levels of contract review. The first is a "strict" or thorough level of review, such as that historically used by the Federal Energy Regulatory Commission. The regulatory agency evaluates the appropriateness or reasonableness, under regulatory principles, of every contract provision in great detail. However, such a careful review might stifle domestic and/or foreign investment, because there is a disincentive to invest where investment and operating decisions are aggressively reviewed and penalized after the fact with perfect hindsight by regulators.

A second form of contract review is by benchmarking. A benchmarking style of contract review would look to the markets or to industry-wide values for prices and other service-related terms and would alter those terms only as required to protect the public.

This style of contract review is often referred to as light-handed regulation. To be properly used, no party should have market power and a market or other benchmark must be ascertainable. When properly used, the benchmarking approach would approve a contract based on market forces unaffected by monopoly power or industry-wide values that are not affected by actions of any individual regulated entity. Here are a few examples. One might use the cost of similarly situated utilities as a benchmark or yardstick against which to judge the reasonableness of the utility's cost. Another example is that several state commissions look to industry-wide heat rate standards to evaluate power plant performance. Another example, in the United States, several state commissions use the natural gas markets as a benchmark against which to determine the reasonableness of the electric utility's or gas distribution company's purchased gas costs. As wholesale electricity markets become more robust, a greater use of market-based benchmark standards is expected.

The third form of contract review is a public interest review, which has been traditionally used by U.S. state commissions, that asks, sometimes in advance, sometimes with hindsight, whether the contract serves the general public interest. If it does, it is approved. Public interest reviews are generally used for relatively non-controversial matters, such as securities issuance approvals. However, sometimes in the United States, even a public interest review can become controversial, for example recent state commission public interest reviews of proposed mergers and acquisitions. The major reason these reviews are becoming controversial is the market power consequences that such mergers have on nascent competitive markets. At both the federal and state level, American regulation is moving toward the benchmaking style.

Inter-Governmental Regulatory Agency Relationships

In all countries, numerous other governmental agencies regulate different aspects of utility operations. These might include, for example, environmental agencies for water, air, and waste pollution; anti-monopoly and unfair trade practice agencies; nuclear safety agencies; financial reporting and accounting agencies; job safety agencies; building code and standards agencies; standards and measurement agencies (dealing with metering and technical control); as well as Power Exchanges and/or Independent Transmission System Operators. In many, if not most instances, it is sensible for these functions to be carried out by another independent agency.

In the United States, there are three possible types or levels of inter-governmental regulatory agency relationships that commissions can have with other specialized regulatory agencies. The first level or type of relationship is one where there is both an overriding public interest in matters such as the environment and/or safety and the public utility regulatory commission lacks expertise relative to the specialized regulatory subject matter. Immediate examples are the relationship between the public utility regulatory commissions and the federal and state Environmental Protection Agencies concerning air, water, and solid waste pollution and the Nuclear Regulatory Commission on matters of nuclear safety. In such situations, the public utility regulatory commissions reflect the cost of complying with those agencies' regulations and decisions in their activities, including the setting of rate and revenue levels. The economic regulatory agency does not

make its own independent evaluation of the environment or nuclear safety, or of what the environmental or nuclear safety standards should be.

A second level or type of relationship is one where the public utility regulatory commission has relevant expertise and may have concurrent (co-equal) jurisdiction with other specialized agencies, because of the special knowledge that the public utility regulatory commission brings to the issues. The best examples here deal with anti-monopoly, unfair trade practice, and financial reporting activities. For example, state public utility regulatory commissions have specialized knowledge about utility services markets, utility market structures, potential market abuses by affiliates or other entities that have cross-ownership, and behavior, reporting, and accounting rules that can hold these practices in check. As such, the U.S. Department of Justice and the Federal Trade Commission together with relevant federal agencies recognize that the state public utility regulatory commissions have concurrent, if not primary, jurisdiction on these issues.

What is important is that the regulatory agency always coordinates its regulatory policies with other agencies whenever it is determining policies that affect the functions carried out by the other agencies. The regulatory agency must reflect and respect the policies of such other agencies in its rates and other decisions. Conversely, these other agencies and entities should have transparent policies that the regulatory agency can take into account in its own policy formulation.

A third level or type of relationship is one where the public utility regulatory commission sets up and relies or participates in the establishment of independent self-regulating entities over which it may exercise jurisdiction as to certain matters. Such is the still evolving relationship between state and federal public utility regulatory commissions and Independent Transmission System Operators (ISOs). An ISO, in the United States, is a group of transmission-owning utilities and transmission-dependent entities, including marketers, brokers, generators, other utilities, and wholesale purchasers, that have voluntarily formed an organization which, at a minimum, operates the transmission system in a non-discriminatory and reliable manner that does not advantage any transmission or generation owner in the market. The ISO can also take on functions such as dispatching, redispatching, being the purchaser of ancillary transmission services, providing transmission pricing (both during congested and non-congested periods), as well as long-term transmission planning. Both state and federal agencies are involved in the formation of ISOs, the establishment of an ISO governance structure that is independent of the interest of the utility owners, the setting up of alternative dispute resolution mechanisms, and the approval of general operating rules. State commissions are often on ISO advisory committees. State commissions in single-state ISOs, such as New York and California, have a larger role in the regulatory oversight of the ISO and its operations. States in multi-state ISOs, in addition to membership on advisory committees, use their authority over distribution entities, and over approval of transmission investments and siting to influence the ISO and its policies. The day-to-day operations of the ISO are, however, of necessity, a self-regulated operation of the ISO. Nevertheless, the ISO and its activities are subject to regulatory oversight by state and/or federal public utility regulatory commissions.

A U.S. regulatory agency, operating in conjunction with an ISO and a market for electric or natural gas supply, does not regulate the price of supply established by that market. Rather, the agency examines the market – its structure and the manner of its operation – to assure that the prices set by that market are not affected by monopoly power of any market participant. The agency further examines and, when appropriate, may direct changes in ISO actions, governance rules, other rules or determinations where these fall within its jurisdiction (i.e., for example, determinations of generation need for purposes of adequacy and reliability or transmission siting). The agency may also participate in ISO proceedings or communicate its views directly to the ISO governing board on matters affecting its jurisdiction. Finally, the agency may participate in the debate and even decide disputed issues respecting ISO governance procedures or substantive operations, and may serve as an appellate tribunal upon ISO decisions on matters falling within its jurisdiction. Both the federal regulator and state agencies within which the ISO is fully located exercise greater command and control authority over the ISO, whereas state agencies in a multi-state ISO seek to influence their ISO's actions through consultation, participation in ISO proceedings, or through exercise of their in-state jurisdiction on ISO members.

Synopsis of Committee Discussion

The CEE/NIS delegates in Yerevan focused their discussion on the effect that long-term contracts might have on the long-term competitiveness of the generation market as well as market power problems that might result if all of the generation were sold to one entity. It was concluded that there is an important distinction between privatization and competition. Utilities in the United States are, for the most part, already privatized. The current regulatory direction in the United States is toward greater competition. In CEE/NIS countries, on the other hand, the privatization process is now happening. Long-term contracts and group sales of assets might initially make privatization more feasible because they create value in the assets being sold. The delegates acknowledged the tension that may exist at this time between pursuing privatization and pursuing competition.

3rd Annual Regional Energy Regulatory Conference for Central/Eastern Europe and Eurasia

Technical Losses and Commercial Losses

December 1999

Tariff/Pricing Committee Member Countries:

Armenia, Estonia, Georgia, Hungary, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, Moldova, Poland, Romania, Russian Federation, and Ukraine

Technical Losses and Commercial Losses

Technical losses and commercial losses are a major source of lost revenues in the CEE/NIS countries. Major efforts to mitigate these losses will become an integral part of any overall solutions in tariff and pricing policies.

Technical Losses

Technical losses refer to losses related to physical plant. For both electricity and gas utilities, many, if not most, of these technical losses result from losses in the delivery system. Such losses are generally referred to as line losses. In the case of gas utilities, gas line loss may be attributable to line leakage, inaccurate meters, inaccurate meter reading, or pressure differences throughout the system.

Electricity line losses are a natural part of transmitting and distributing electricity. These losses occur as voltages are stepped down to levels useful to customers. As such, line losses are greater for customers taking electricity at lower voltage levels.[1] Problems arise, however, when the electricity line losses go beyond levels that are considered to be acceptable or reasonable under proper utility operating practices.[2] In particular, electricity line losses can result from overloading particular transmission or distribution lines, or both. The more heavily loaded the lines, the greater the line losses. As a result, when engaging in economic dispatch, an electric utility should account for line losses in determining the dispatch order.

In the United States, the typical treatment of technical losses in rates involves customers being charged for only a reasonable amount of line loss as pre-set by the commission. In addition to setting an allowance for reasonable line losses, the commission periodically revisits the pre-set line loss to assure consumers that they are not overpaying. Thus, reduction of technical losses could require creation of a flexible mechanism of penalties when actual technical losses exceed the limit set in advance by the commission. Alternatively, if technical losses were established in the tariff at a level reflecting proper utility operating practices, then the utility would automatically be penalized when losses exceed that level. All else being equal and, absent any adjustment to the line loss, a reduction in line loss below the commission's pre-set level of allowable line loss results in the utility's receiving a greater margin from existing rates. Allowable line losses are typically charged to all consumers, including transportation consumers, not merely the utility's own ultimate sales consumers.

Representatives of the CEE/NIS countries asked what level of technical losses are permitted in the United States. Commissioner Eachus of Oregon replied that each state commission sets technical losses at a level that the Commission considers reasonable.

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[1] This is one reason why tariffs to small consumers should be higher than those for large consumers.

[2] A later section of this paper discusses the issue of setting regulatory standards for technical losses.

This level is based on historical losses as well as the Commission's understanding of what

is technically achievable, given a utility's own unique network. Chairman Movsesyan of the Energy Regulatory Commission of Armenia pointed out that if certain levels of technical losses are achievable and setting incentives to reach that level is based on historical records, then having an accurate distribution metering system is critical.

Commercial Losses

Commercial losses come from a variety of sources, all of which have in common that energy was delivered but not paid for. One source of commercial loss is the theft of utility services, either by directly bypassing meters or by tampering with meters. Another source is through meter reader fraud. In this situation, although the meters themselves have not been tampered with, the meter reader takes bribes to report inaccurate energy usage. A third source of commercial losses is master metering without individual meters. Often apartment buildings or large complexes have a master meter, but no individual sub-meters. Consequently, it is not possible to accurately assign individual usage; as a result, consumers may not feel obligated to pay for energy usage that has been assigned to them. A fourth source of commercial losses is un-metered utility service. Without meters, it is highly improbable to accurately bill for energy usage. Each of these first four causes of commercial loss lies within the control of the distribution company. The typical rate treatment within the United States is to simply place the distribution entity totally at risk for a failure to recover these kinds of commercial losses.

Two additional sources of commercial losses exist. The first is non-payment by customers who can afford payment of their energy services; the second is non-payment by customers who cannot afford payment of their energy services. In the United States, those who can afford payment of their energy services but fail to make payment are disconnected.[3] While those who cannot afford payment of their energy services are placed under one of several possible programs designed to collect as much as the customer can afford to pay. Among the latter programs are life-line rate programs, budget billing programs to even out bills during high energy usage periods, and percentage of income programs. Percentage of income programs provide that the maximum bill that an individual will pay is set at a percentage of their income. Arrearages and bad debts as a result of these programs are recovered from other customers or are recovered from direct government subsidies. If a customer who formerly could not afford payment fails to pay the newly-set affordable bill, he is subject to utility service disconnection.

Chairman Movsesyan of the Energy Regulatory Commission of Armenia noted that again having an accurate distribution metering system is critical for creating incentives to reduce commercial losses: the customers know what they are being charged for and the distribution entity knows the actual usage. This highlights the point that

[3] One meaning of affordability is the condition under which consumers are able to pay for utility services without foregoing the purchases of other goods and services that are essential to their livelihood.

lowering both technical and commercial losses is, to a large extent, linked to installing new metering devices. But the ability of entities to recover the cost of installing such new metering devices is compounded by the immediate financial problems caused in large part by technical and commercial losses. Chairman Movsesyan suggests that this financial

problem might call for some of these technical and commercial losses beyond a certain level to not be recoverable through rates. (The level should be set carefully so as to not jeopardize the reliability or safety of the system.) Specifically, Chairman Movsesyan then called for distribution entities to internally generate capital (in a sinking account, for example) to be used as a source of funding to replace antiquated or non-existent meters with automated meters and automated meter readers; these meters would provide accurate records to reduce commercial losses, would cut personnel expenses, and would provide information that could be used to cut technical losses. Alternatively, when funds are needed for such meters or for repairs to reduce technical losses, the utility entity might borrow capital that is recoverable in future rate increases. Ultimately though, it is in the interest of both the utility and the customer to reduce both technical and commercial losses.

Mitigating Losses

The reduction of both technical and commercial losses confronts regulatory agencies in the CEE/NIS countries with a major challenge.[4] Although important in making utilities more productive, energy efficient, and more financially solvent, reductions of either form of loss will require large investments. Of particular interest and more complicated for regulators are commercial losses, as they constitute a significant revenue loss for regulated utilities, which for some may jeopardize their ability to meet loan obligations. Countries such as Armenia, Georgia, Ukraine, Lithuania, and Latvia have taken initial steps toward reducing losses.

In Georgia, the Georgian National Electricity Regulatory Commission (GNERC) was intensely involved in the privatization of Telasi. At the time of the privatization, Telasi had commercial and technical losses of up to 40 percent. As a part of the privatization negotiation and contracting process with the American firm AES, the GNERC required that AES would make investments and take actions so that commercial losses would decrease. In exchange, the company has a ten-year tariff extending to the year 2008. As a result, the company is making appropriate investments to reduce both technical and commercial losses. The goal of these investments is to reduce commercial and technical losses to approximately 10 percent. As part of the incentive to reduce commercial losses, AES is allowed to recover only the costs associated with technical losses in tariffs. Ultimately Georgia aims to reduce combined technical and commercial losses to 7 to 10 percent.

[4] The representative from the Georgian National Regulatory Commission spoke of the difficulty of tariff setting caused by commercial losses for electricity and natural gas resulting from neglect by meter readers and non-payment of bills by consumers.

In Ukraine, the wholesale tariffs only take into consideration technical losses. Commercial losses are not reflected in tariffs. Metering capabilities are being updated locally.

The representative of the National Control Commission of Prices for Energy Resources and of Energy Activities in Lithuania (NCC) expressed his opinion that

commercial losses are complex and that perhaps each country will have its own solution. He is more concerned with technical loss problems, particularly since the electric and gas networks are from "Soviet times." Such technical losses must be addressed gradually as infrastructure improvements can be implemented. In Lithuania gas pipeline losses have been at less than 1 percent (from .5 to .7 percent), while local distribution line losses have been at about 2.5 percent. The goal is to get the technical losses down to about 1 percent. Currently, the major source of gas technical losses is attributable to the metering equipment.

The representative from the Latvia Energy Regulatory Council stated that total losses are at about 10.94 percent of which 7.5 percent are technical losses and the remaining 3.6 percent are considered to be commercial losses. The commercial losses are included in the tariff. Latvia has special methodologies for calculating technical and commercial losses; comparisons are difficult, however. A goal of the government is to reduce technical losses to no more than 2.3 percent for the gas network. The district heating network has the highest level of technical losses. All losses are currently incorporated into the tariff.

Whether technical or commercial in nature, losses produce undesirable outcomes. Technical losses drive up the cost (or obversely, drive down the productivity) of delivering electricity and natural gas. Increased costs translate into higher prices for consumers or lower profits for utilities, or both. A major cause of technical losses in the CEE/NIS countries has been the deferral or neglect of badly needed operation and maintenance expenditures. As discussed below, serious consideration should be given by the CEE/NIS countries to establishing a standard for technical losses in terms of rate base treatment or in setting a targeted cost of service.

Commercial losses, caused mostly by deficient metering, billing, and bill-collecting practices, have seriously jeopardized many of the utility entities in the CEE/NIS countries. When included as a cost-of-service component, commercial losses translate into higher prices for full-paying consumers. Because of the high commercial losses in some of the CEE/NIS countries, the burden on paying customers could be significant.[5] To many observers, the situation where some consumers pay for the delinquency of other consumers violates a basic "equity" standard. This is particularly true in the case of non-paying customers who can afford to pay but do not for other reasons.

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[5] This is unlike developed countries such as the U.S., where the effect of non-payment on paying consumers is generally minuscule.

Some of the CEE/NIS countries have begun to address the commercial-losses problem by installing meters and by installing information-system software. In Ukraine, for example, one utility has instituted new reading procedures and installed new meter reading equipment. The result has been a substantial improvement of cash collections from consumers.

Overall, an important issue in the CEE/NIS countries revolves around how

technical and commercial losses should be reflected in tariff. Another important issue is identifying incentive mechanisms and "fines" applications for reducing losses.

<u>General Approaches</u>

Regulatory approaches for reducing technical and commercial losses can be grouped into two broad (but not entirely distinct) categories:

(1) command-and-control rules
(2) incentive based

Command-and-control rules, in general terms prohibit or discourage the utility from undertaking a specified objectionable practice by the threat of a monetary penalty. In comparison, an incentive-based approach attempts to change a utility's behavior through explicit monetary rewards and penalties across different levels of actual performance.

Technical Losses

As discussed above, the primary reason for technical losses is neglect or deferral over a number of years of operation and maintenance expenditures. In reducing technical losses, a utility needs to have adequate financial resources and, in addition, sufficient incentive. Penalty or sanction schemes, if adopted for a utility, should not be overly burdensome to prevent the utility from retaining adequate financial resources to carry out the activities needed for reducing technical losses. Under the threat of penalty, the utility faces a dichotomous choice: receive a specified amount of revenues when attaining the targeted level of losses or receive fewer revenues when failing to do so.

Under an incentive-based mechanism, the utility would recover a different share of its actual costs depending on the magnitude of technical losses. Specifically, on a continuum the utility would recover a higher percentage of its costs as its technical losses decline. As an illustration, a benchmark level of technical losses would be established, say 15 percent. At this level, the utility would recover all of its actual costs from consumers. Deviations from this level would have cost-recovery consequences, namely, a portion of the incremental or decremental costs would be shared between the utility and consumers. Assume, for example, that actual technical losses are 20 percent, with costs increased by one million monetary units (relative to costs at technical losses of 15 percent). An incentive mechanism could allow the utility to absorb half of the cost increase while the other half could be recovered from consumers. Symmetrically, a utility would be able to retain a specified share of the cost savings from technical losses below the benchmark level.

Both the command-and-control and incentive-based approaches can be incorporated into a license or concession agreement between a utility and the government or into the calculations of allowable revenues under either a rate-of-return or price-cap form of regulation. With regard to licenses or concessions, renewal to an entity may hinge on whether technical losses fall below a targeted level. A license may specify a minimum level for technical losses, for example, 20 percent, below which an entity may be denied renewal rights.

Several regulatory-agency activities for addressing technical losses seem essential. First, an agency needs to monitor losses over time; a statistical measure of actual technical losses would provide information on their severity. (This requires that regulatory staff members have access to the necessary information which can be compiled from mandated utility reporting requirements.) Second, targeted losses need to be established; this task is implicitly a cost/benefit issue identifying the level of technical losses at which the utility's cost of service would be at a minimum (although lower technical losses, by and in themselves, would lower a utility's costs, the expenditures required to achieve lower losses might initially drive up a

utility's costs);[6] targeted losses could reflect what a regulatory agency considers reasonable utility actions over some specified period of time. Third, a time path for achieving targeted losses would be required; for example, a target of 10 percent to be achieved in five years may be established. Fourth, penalties and rewards (the latter for an incentive-based approach) would have to be calculated. For example, how much less revenue should a utility be allowed to collect when its technical losses are 15 percent versus 12 percent? Fifth, under an incentive-based approach a determination has to be made regarding the distribution of benefits from reduced losses between a utility and its consumers. If, for example, a decline of technical losses results in a 10 percent decline in electricity transmission costs, what portion of that decline should go to consumers in the form of lower prices rather than to the utility in the form of higher profits?

Commercial Losses

Since commercial losses originate for various reasons, a single approach for mitigation may not suffice. Certainly utilities have some control over the magnitude of commercial losses; but even with their best efforts, some commercial losses would still continue. Consequently, an effective policy of reducing commercial losses may require regulatory action directed at both utilities and consumers.

Commercial losses can be reduced in several ways. First, privatization of the distribution function can provide greater incentive for the utility to collect bill payments from consumers; this is based on the observation of utilities throughout the world that a private firm would be more motivated than a state-owned entity in collecting payments for billed service.

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[6] Some representatives of the CEE/NIS countries discussed the large investments that will be needed to reduce both technical and commercial losses. In Ukraine, for example, most utilities include in their rate base significant expenses for updating their metering and billing systems.

A second mitigation approach would involve eliminating the legal and political barriers to shutting off service to privileged and other non-paying consumers. Loud complaints would be expected from those consumers who have long failed to pay their bills; they may believe that they have an entitlement to "free" utility service. Armenia expressed the urgency of identifying regulatory approaches for reducing commercial losses for state-owned utilities. These include removing legal, technical, and financial barriers to disconnect non-paying consumers, as well as measures that would force distribution companies to step up their collection efforts.

Third, aggressive action by a distribution company in receiving payment should reduce commercial losses; the key to this approach is a highly motivated utility driven to minimize commercial losses. Giving a utility this incentive may require regulatory action. For example, an agency may prolong the time in which a utility could shift delinquent or non-paying accounts to bad debts; because the utility would have to wait longer to recover the revenue losses associated with unpaid bills from paying consumers, it may have an added incentive to more aggressively collect payments. A stronger, and perhaps preferred, incentive would result from a regulatory policy of allowing the utility to completely absorb the adverse revenue effects from commercial losses.

Finally, strict penalties may be assessed on those individuals who tamper with meters. The regulatory agency's enforcement authority in this regard, however, may be greatly limited or non-existent. Consequently, co-ordination between the regulatory agency and other units of government may be required.

Synopsis of Committee Discussion

At the Yerevan meeting, the delegates of the CEE/NIS countries discussed how to distinguish between technical losses and commercial losses. It was concluded that total losses on an electric or gas network are known, and technical losses can be calculated. Total losses minus technical losses equals commercial losses. The delegates reached a consensus that all or a substantial portion of commercial losses should be borne by the company, particularly distribution systems serving end use customers. Further, achievable, measurable goals should be put in place for companies to reduce technical losses. If the distribution company suffers commercial losses, it should be allowed the option of disconnecting the customer and shutting off the customer's utility service. In addition, the distribution company in the United States would have available use of the police and the courts to combat commercial losses resulting from theft or fraud. As a result of its service termination policy, Lithuania has dramatically cut commercial losses. An additional are of consensus among the delegates concerns the difficulties associated with customers who cannot afford to pay. Customers who cannot afford to pay need their essential utility services protected. In the United States, it is concluded that the best way to address affordability problems of the poor would be through government welfare and other programs to help the poor. The cost of such programs should be borne by the government, not by the distribution company.

3rd Annual Regional Energy Regulatory Conference for Central/Eastern Europe and Eurasia

Cross-subsidies

December 1999

Tariff/Pricing Committee Member Countries:

Armenia, Estonia, Georgia, Hungary, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, Moldova, Poland, Romania, Russian Federation, and Ukraine

Cross-Subsidies

Introduction

The current tariffs in CEE/NIS countries generally fall below the costs of providing electricity and natural gas to retail consumers. In addition to this utility-to-consumers subsidy, the magnitude of cross-subsidies between customer classes varies across categories of consumers.[1] In Ukraine, for example, residential and agricultural consumers are currently being subsidized by industrial consumers. Other CEE/NIS countries have tariff structures with varying degrees of customer class cross-subsidies. Committee representatives from some of the CEE/NIS countries articulated the severity of the problem by remarking that up to 50 percent of utility consumers in their countries could be eligible for a preferential tariff based on factors other than the ability to pay. Favored customers who benefit from cross-subsidies have the cost of their service, at least in part, paid for by other customers, by utility investors where privatization has occurred, or by taxpayers where it has not.

As certain Committee members noted, measuring the cost of a particular customer's or customer class's service is difficult and can be controversial. Many cost items contribute to the service of different customers or customer classes; these costs must be allocated between such customers or classes in order to permit identification and measurement of a subsidy. Nevertheless, as will be explained below, generally accepted methods of cost allocation for measuring such subsidies do exist and these cross-subsidies should be identified and eliminated.

An additional cross-subsidy issue is the treatment of low-income or otherwise needy customers. Some American states require service to be provided to low-income citizens at less than fully allocated cost. This has the effect of requiring other customers to pay the cost not imposed on this need-based group. Most American states provide need-based assistance to qualified customers only through targeted-rate-reduction or government-welfare programs. The government is generally viewed as best able to identify those customers who need assistance. Energy providers are not as capable as the government in identifying qualified customers. Instead, they should be left to concentrate on the efficient production and delivery of energy services in accordance with common commercial practices.

A further cross-subsidy issue, defined below and discussed more fully in the paper on technical losses and commercial losses, is the ratemaking treatment of commercial losses. Whether utility consumers should be required to pay the costs from commercial losses is an issue being debated in the CEE/NIS countries. In the U.S., consumers generally shoulder the burden of commercial losses. In contrast, in the CEE/NIS countries, where commercial losses are much higher, the practice is to have utilities bear the responsibility for these losses. The financial burden on utilities can be significant, as commercial losses generally lie within the 10 to 20 percent range.

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[1] This implies that not only are consumers paying too little for utility services but that some consumers are paying too little relative to other consumers.

As noted, different forms of cross-subsidy exist and their identification can be both difficult and controversial. Thus, it is not an easy task to set forth a comprehensive definition which encompasses all of them. The central principal embodied in each of them, however, is that one group of customers, investors, or taxpayers is required to bear the costs of providing energy services to a more favored group. Continuing with the current levels of cross-subsidies jeopardizes the objective of countries to transform public utilities into commercially viable enterprises.[2] Eliminating or reducing cross-subsidies constitutes an important strategy of countries in allowing utility enterprises to increase their revenues and operate their energy systems efficiently.[3]

Adverse consequences of Cross-Subsidies

Cross-subsidies in the utility sector can lead to serious problems for a country. These problems tend to intensify over time as energy providers encounter increased difficulties in raising needed capital funds to maintain or expand their capacity capabilities. Efforts to reform the utility sector should include, if not begin with, addressing ways to more rationally restructure tariffs in line with economic principles. As discussed later, such efforts are hampered by the unavailability of good data and strong political pressures in opposition to harming the beneficiaries of the current tariff structure.

The adverse consequences of cross-subsidies have several components. First, cross-subsidies are unfair to some members of society. For example, they result in some consumers paying less for utility services than what it costs society to provide them with those services.

Second, cross-subsidies are economically inefficient: they provide wrong signals to consumers on the amount of utility services they should consume;[4] and they may cause the lowest-cost sources of utility services to be under-utilized or un-utilized when the prices for other sources (e.g., state-owned enterprise) are being subsidized. In setting tariffs, economic efficiency should be an important consideration as it takes into account the aggregate benefits and costs.[5] When a new tariff is set, for example, to improve economic efficiency, the implication is that societal welfare has increased.

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[2] Such enterprises stand on their own by charging high enough prices to recover their costs, including the cost of capital.

[3] Some countries also have the problem of distributors not properly compensating the private generation company for the electricity it provides. In effect, the distributor receives a cross-subsidy from the generation company by under-paying for purchased wholesale electricity. The major reason for this is commercial losses. In the U.S. "settlements" disputes regarding wholesale energy transactions rarely occur, partly because of good metering, but when they do the parties can require resolution from the federal regulator or the courts.

[4] Economic inefficiencies also occur when the utility purchases inputs such as different sources of energy at subsidized prices. Even though the subsidized prices represent the cost to the utility, they understate the true cost to society

[5] In the context of tariffs, economic efficiency refers to the relationship between price and marginal cost. Economic efficiency is maximized when price and marginal cost are equal.

Third, cross-subsidies generally discourage private investments; a private power producer being required to offer wholesale electricity at a price subsidizing retail consumers, for example, would tend to be discouraged from entering the market; this is especially true if it is unable to earn what it considers a minimally acceptable rate of return.[6]

Fourth, cross-subsidies implemented over a long period of time inevitably lead to shortages; this is exemplified by inadequate new capacity and under-maintenance of existing capacity; in addition deterioration of service quality and safety may ensue.

Finally, cross-subsidies can cause degradation of the environment. By under-pricing utility services, consumers place greater demands on a utility system; utilities will also have less financial resources to replace existing capacity with new capacity, some of which make use of more environmentally benign technologies.

Identifying and Measuring Cross-Subsidies

For utility-to-consumer cross-subsidies, the generally accepted measure relates to the utility's cost of service or revenue requirement. The cost of service refers to the legitimate costs that a utility incurs to meet the demands of consumers.[7] Whenever a utility's tariffs are set at a level that precludes the utility from recovering these costs, a cross-subsidy is said to exist. To put it differently, a cross-subsidy is the result of a utility's expected revenues being less than its expected cost of service.

Identifying and measuring customer class cross-subsidies is more controversial. For example, does an inter-customer-class cross-subsidy exist whenever the utility receives a higher rate of return from one group of consumers relative to other groups? Or, do cross-subsidies within consumer classes require that one or more groups of consumers are paying for utility services at less than incremental or short-run marginal cost? In either case, certain consumers receive preferential treatment with other consumers possibly compensating the utility for lost revenues.

Customer class cross-subsidies are measured through a cost-of-service study, which involves a two-step process. First, the total costs of the utility are calculated; these costs represent the total revenues the utility is allowed to recover from consumers. These revenues determine the overall level of rates. The second step assigns by customer class responsibility for recovering the utility's total costs.[8]

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[6] The rate of return would have to equal at least the producer's cost of capital.

[7] "Legitimate costs" include only those costs incurred to meet consumers' demands that reflect sound utility management decisions. For example, did a utility decision make good use of the information available to the utility's management at the time the decision was made?

Non-utility-related expenditures, such as those to implement certain social programs, may not be considered legitimate costs, thereby excluded from utility prices. Examples include expenditures for day care centers, retirement homes, and health spas. In the U.S., expenditures for utility-related social programs, such as energy assistance to low-income households, are included in prices only if they are made at the mandate of the government.

[8] A third step in developing actual prices is what is called rate design. For example, rate design establishes a set of prices charged to each consumer class for varying levels of consumption.

Cost allocation normally involves assigning costs by utility function (e.g,

generation, transmission, distribution), rate components (e.g., energy, demand, customer), costing periods (e.g., peak, off-peak, non-time differentiated), and consumer classes (residential, commercial, industrial).

With regard to rate components, separate demand, energy, and customer charges may be imposed on consumers. Demand charges may reflect the cost of meeting an industrial consumer's maximum demand; these costs may include the cost of capital and other fixed expenses associated with generating plants, transmission lines, substations, and part of the distribution system. Energy charges may reflect the costs associated with the amount of kilowatt hours consumed; for an electric utility, these costs are largely fuel and labor expanses. Customer charges incorporate the cost to the utility of a consumer having access to its system.

In sum, setting tariffs on the basis of cost-of-service principles requires a definition of costs and a method for allocating these costs to different consumers. As practiced in the U.S. and other countries, tariff setting involves regulators looking at factors, such as economic development and energy conservation, in addition to costs. These factors take into account regulatory objectives that may be mandated by law.

Inter-customer-class cross-subsidies are particularly difficult to measure. Analysts need to define the relevant costs; for example, should long-run marginal cost be used, or is short-run marginal cost or even average cost a better measure to apply? There is also the issue of how broadly individual consumer groups should be defined. In many countries, consumers are grouped into the categories residential, commercial, and industrial.

As mentioned above, a cost-of-service study can be used to allocate costs to each category of consumers. Appropriate cost allocation can go a long way in eliminating cross-subsidies across the different categories of consumers. But, it does not, and it should not be expected to, eliminate all cross-subsidies. For example, while all residential customers would be subject to the same tariff, it is reasonable to assume that the utility's average cost in serving individual households is not the same. Consequently, those households who impose the lowest average cost to the utility are subsidizing the other households.[9] Unless cost allocation is done at an individual consumer level or on an hourly basis (which would invariably be cost-prohibitive), cross-subsidies among consumers cannot be completely eliminated.[10]

Notwithstanding this limitation, it is still reasonable to apply a cost-of-service

[9] In the U.S., for example, agricultural households are normally lumped with urban households. Since a utility incurs higher costs to deliver utility services to rural areas, it can be argued that urban households are subsidizing agricultural households.

[10] A view expressed during Committee sessions indicates concern about efforts to reduce or eliminate cross-subsidies. This view asserts that (1) no standard exists for the calculation of costs, (2) tariff setting is an art driven by politics, (3) allocating costs across consumers is a problem, and (4) broadly defining consumer categories precludes eliminating all cross-subsidies.

study disaggregated by categories of consumers. Such a study would eliminate much of the cross-subsidies that would otherwise exist if no such study is done. Tariff setting should be viewed as an art, where judgment by the analyst and the regulator is frequently

required in such matters as the allocation of common costs across consumer groups and the categorization of consumers. Although cost-of-service analysis has its flaws[11] — it is certainly less than perfect — the pertinent question is whether other methods for setting tariffs designed to reduce cross-subsidies are any better. Currently the answer seems to be there are *not* better methods.

Cost-of-service studies are not easy to carry out and certainly they do not produce precise results. On the other hand, they offer valuable information requiring judgment by analysts and regulators. For example, although utility rates in the U.S. generally follow cost-of-service principles, they do often deviate from strictly cost standards for various reasons.

How to Reduce Cross-Subsidies

The effort to reduce cross-subsidies stems from the recognition that social objectives have imposed a high cost on the utility sector as well as the overall economy. To reiterate from an earlier discussion, these costs include economically inefficient energy systems, inadequate investments, and degradation of the environment. As a political matter, in spite of the high costs that may be attached to cross-subsidies, consideration should be given to avoiding an abrupt change in tariffs. Dramatic increases in tariffs over a short period of time could unduly burden certain consumers, specifically low-income households, unless coordinated with government social safety-net programs.

Price re-balancing to eliminate customer class cross-subsidies varies price increases over time across different classes of consumers. For example, assume that a cost-of-service study reveals that residential prices should be higher relative to industrial prices, say, 20 percent higher. Annual price increases for residential consumers could be set higher than for industrial consumers so that after a period of time the residential-to-industrial price ratio increases by 20 percent.

In conjunction with a gradual-reduction cross-subsidy policy, public education by the regulatory agency or some other branch of government may be crucial to gain public approval. Even though cross-subsidies can result from legislative and central-government actions, and may be beyond the regulatory agency's control, the agency may nevertheless serve a useful purpose by applying cost-of-service principles to identify cross-subsidies. Information can be disseminated to the general public concerning the rationale for reducing cross-subsidies, including why it would be beneficial to the country and for consumers in the long term. For example, a financially viable utility sector would be more productive, efficient, reliable, and safe, thereby benefiting consumers. The regulatory agency could also publicize the cost-of-service method and standards used to

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[11] One flaw centers on the allocation of common and joint costs among consumer classes and services.

measure cross-subsidies. This act should help to gather more public support for ending or reducing cross-subsidies, or redirecting them so that they are based on need and not on other political criteria.

Reducing cross-subsidies and re-balancing rates in line with cost-of-service principles can be achieved with rate-of-return regulation or price-cap regulation. Under either, a cost-of-service study along with appropriate cost allocation methods can be used to calculate "target" prices. Current prices can be adjusted so that at the end of a specified period prices will reach the targeted levels. Prices for individual categories of consumers may vary, in terms of percentage, to mitigate price distortions across consumer groupings. For example, under price caps allowable price increases can be higher for those classes of customers that have been historically the beneficiaries of cross-subsidies.

A major obstacle in reducing cross-subsidies is the political opposition by interest groups who perceive the taking away of benefits. These benefits, which some may consider as entitlements, are in the form of lower prices for utility services. By more rationally setting prices to reduce cross-subsidies, some consumers would be expected to pay higher prices, especially in the short term. For consumers with moderate or high incomes, higher prices would pose a lesser burden: although allocating a higher percentage of their incomes to utility services, these consumers would not likely have to forego other essential goods and services.

The situation for low-income consumers is more serious. Higher utility prices may burden their budgets to where they may have to choose between utility services and other essential goods and services. In this circumstance, the government has two choices: (1) raise income support payments to low-income consumers through the governmental budgeting process to compensate for the higher prices for utility services, or (2) require utilities to target lower prices to only low-income consumers.[12]

The first choice should be preferred in terms of a country's objectives to minimize tariff distortions in its utility sector and to make transparent the true cost of subsidies. These distortions, historically large in magnitude for many of the CEE/NIS countries, can be traced to past efforts to achieve social objectives through utility tariffs. Countries now realize that such endeavors, while perhaps commendable in intent, have incurred a high cost in degrading the utility sector. The investment community frowns upon reliance on utility tariffs to fund social programs; and economists warn economic-inefficiency would follow, as other governmental mechanisms for achieving social objectives are preferred.

Synopsis of Committee Discussion

The principal focus of discussion in Yerevan was that cross-subsidies are difficult

[12] It can be argued that a means-tested cross-subsidy would produce less inefficiencies than a broad-based cross-subsidy in achieving the same objective of making utility services more affordable to low-income households. This approach has been extensively used in the U.S.

to eliminate. Nevertheless, it was agreed that commissions should attempt to do so. Further, even when commissions have difficulty in eliminating cross-subsidies, they must educate other government organizations, including the parliament or legislature, as well as the general public as to the desirability and need to do so.