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Regulatory Assistance for Lithuania

Tariff Implementation Project

Final Report

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Regulatory Reform and Energy Sector Restructuring in Central and Eastern Europe and the Baltics

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Section 1 Project Summary and Conclusions

This report describes work under the Tariff Implementation Project, undertaken as part of a broad United States Agency for International Development (USAID) program of regulatory assistance to the energy sectors of Central Europe and the Baltics The work was performed for the National Control Commission of Prices for Energy Resources and of Energy Activities (NCC) in Lithuania

USAID regulatory assistance to Lithuania started in autumn of 1995 Assistance to date consists of three components (1) initial methodology development, (2) methodology implementation, and (3) provision of a resident advisor The Tariff Implementation Project refers to the methodology implementation component

The objective of the initial methodology development was to address several issues relating to the development of the regulatory structure in Lithuania The work consisted of technical assistance in developing electricity, heat, and gas pricing methodologies, description of regulatory practices in selected European countries, and assistance in drafting mission guidelines for the NCC The project was successfully conducted as a joint effort involving USAID technical experts and NCC members and their subcontractors from the Lithuanian Energy Institute

Tasks in the Tariff Implementation Project were structured to provide further technical assistance in the implementation phase of pricing reform for natural gas, electricity, and heating, and were intended to complement the work of the NCC resident advisor Major components of the Tariff Implementation Project included

- Reviewing the existing energy cost structure
- Estimating the financial requirements of the energy system
- Reviewing and modifying the energy cost allocation method
- Introducing incentive and marginal cost-based energy pricing concepts
- Supporting tariff design and implementation process
- Considering the impact of tariff increases on sensitive groups of customers
- Improving public understanding and participation in regulation and in the energy tariff setting process

Messrs Floyd Davis, Howard Menaker, and Miljenko Bradaric of Bechtel participated in the project Mr Davis and Mr Bradaric made an initial data gathering trip in September 1997 This visit was followed by an October 1997 trip timed to allow participation in a seminar at the Parliament of Lithuania, where Mr Davis and Mr Menaker made presentations In February 1998, Mr Davis and Mr Bradaric traveled to Vilnius for the installation of the resident advisor, Mr Jim Strangways In October 1998, Mr Davis and Mr Bradaric made a final trip to Vilnius to present and discuss their findings Throughout the project, communications and information exchanges were conducted through the internet

The project enabled NCC participation at the first Inter-Regional Energy Regulatory Conference for the Central/Eastern Europe and New Independent States held in Budapest, Hungary on November 17-20, 1997 The conference was sponsored by USAID and the Hungarian Energy Office

The focus of the Tariff Implementation Project has been on advancing existing price-setting methodologies and implementing new methodologies Two complementary price-setting approaches are practiced by regulatory commissions around the world – cost-based regulation and incentive regulation NCC implemented cost-based regulation to ensure that energy prices in Lithuania reflect real economic costs

Cost-based regulation is based on the premise that the prices charges by natural monopolies should be based on their costs A major challenge facing the NCC at its inception was to implement tariff-setting procedures that covered the costs of the various energy service providers in Lithuania Section 2 of this report describes our review of current cost-based procedures used by the NCC and suggests improvements where appropriate One of the shortcomings of cost-based regulation is that service providers often are not given an incentive to reduce costs **Incentive regulation** refers to ratemaking alternatives to traditional cost-of-service regulation Under incentive regulation, rates are typically based on certain targets that do not necessarily reflect the cost of providing that service Various incentive approaches have been applied in other parts of the world to address this issue Section 3 presents a proposed methodology that incorporates incentive regulation Appendix A presents a detailed review of the existing methodology for pricing electricity and how it was applied in the Lietuvos Energia submittal to NCC in 1997 Appendix B presents a detailed revision of that methodology Appendix C presents a realistic example of how incentive regulation could be incorporated into the existing cost-based pricing approach for the power sector

The recent worldwide deregulation trend is to move from traditional pricing regulation, letting market forces set prices where possible Two of the areas where competition has been very successful are natural gas production and electricity generation However, energy sectors in all countries have natural monopolies in transmission and distribution that limit the application of market pricing, and will continue to be subjected to traditional regulation In addition, the Lithuanian energy market is dominated by a single supplier and characterized by over-capacities in electric generation and natural gas production, a situation that will tend to limit the application of competition in these areas in the near future

This report and the accompanying analysis were presented and discussed with NCC staff, and with the local energy tariff experts from the Lithuanian Energy Institute Based on these discussions, our main conclusions and recommendations are

- During the life of the project, NCC made major progress in advancing and implementing energy pricing methodologies
- Development of the detailed cost categorization is needed to support cost-of-service tariff methodologies

- Development of an approach for determining a reasonable level of profit for service providers is needed
- Additional load research and/or metering is required to support the cost allocation process
- A possibility exists for immediate development of incentive pricing regulation in Lithuania It should be possible to implement incentive pricing regulation in a way that is compatible with current cost-based approaches

Section 2 Cost-Based Price Regulation

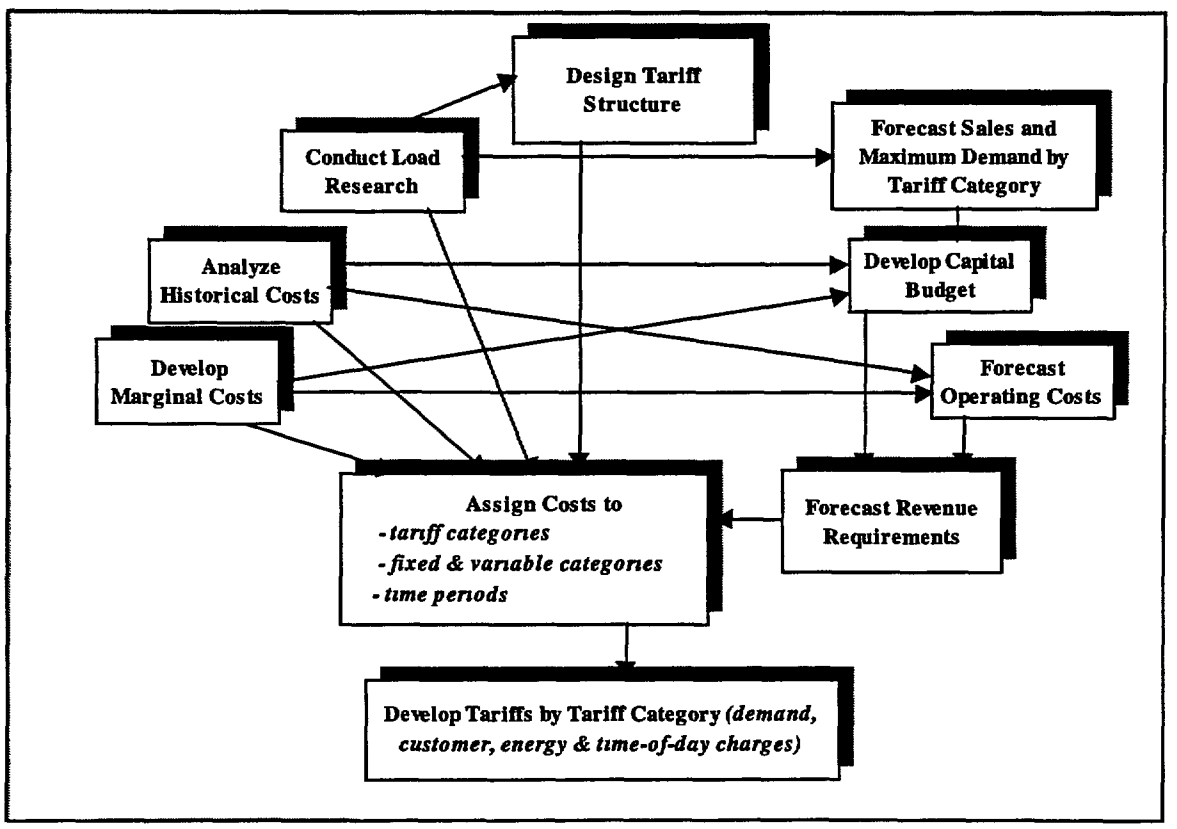
2.1 INTRODUCTION

The NCC currently utilizes a cost-based approach for setting energy prices The key element of any cost-based approach is the allocation of costs to tariff categories, generally referred to a as cost-of-service analysis Section 2 2 is an overview of how a cost-of-service analysis fits into the overall cost-based pricing process, a review of the existing cost-based methodology, and a revised methodology incorporating key elements of the review However, we recognize that the tariff implementation process in Lithuania is a dynamic one and that experience gained over the past few months may suggest additional modifications

2 2 COST-OF SERVICE ANALYSIS

Cost-based tariffs reflect the underlying cost requirements and structure of the energy service provider Figure 2-1 shows the typical steps in setting cost-based tariffs Cost-of-service analyses generally incorporate load research, revenue requirement forecasts, and assignment of costs to various categories A cost-of-service study is generally conducted on a periodic basis to support tariff changes

Figure 2-1 Typical Cost-Based Tariff Setting Process



The major steps in a cost-of-service study are

- Define the boundaries of the enterprise activities to be regulated and period of study
- Calculate overall revenue requirement by itemizing operating expenses and estimating depreciation, "reasonable" allowance for profit and taxes
- Separate costs by function by allocating and classifying costs to each level or type of service
- Classify costs as fixed, variable with sales, and variable with number of customers
- Differentiate costs by time period
- Allocate costs to tariff categories

There are several allocation elements in a cost-of-service study Each cost element for each service provider must be assigned on the basis of causality For example, fuel costs are considered energy production-related costs Each customer class' consumption of each service must be evaluated in order to relate costs to consumption This required significantly load research

Revenue requirements are allocated to energy costs in $/MWh, capacity costs in $/kW-month, and customer costs in $/month Including all three cost components in tariffs allows a greater degree of *unbundling* of the three services provided by a service provider, and thereby provides more accurate pricing signals For the illustrative purposes of this report, we ignore the relatively small customer cost component The capacity component of tariffs can be assessed as either a demand charge on the basis of the consumer's contribution to the system's peak load, or as an energy charge allocated by billing period The latter method is typically applied for consumers without demand meters

Ideally, the accounting data available from the service provider will support the categorization in the cost-of-service study For example, in the U S , there is a uniform system of accounts for service provider reporting to the Federal Energy Regulatory Commission The level of detail in the current system of accounts in Lithuania for reporting service provider costs could be an obstacle to implementing future cost-based regulation Such a system in Lithuania will have to accommodate the potential for direct subsidies, reflection of undervalued assets, allocations between activities using common resources (combined heat and power), and any unaccounted costs

A detailed description of the cost-of-service methodology used in the U S can be found in the *Electric Service Provider Cost Allocation Manual* (published by the National Association of Regulatory Commissioners, January 1992) A copy of this manual was supplied to the NCC in October 1997 Following the general principles described in the manual, we present our review of the recent electric service provider cost-of-service submittal in Section 2 3

2 3 REVIEW OF THE CURRENT METHODOLOGY

In August 1997, Lietuvos Energia submitted a request for a tariff increase This request was accompanied by two spreadsheets the first provided a forecast of revenue requirements, the

second allocated forecasted costs into tariff categories Both spreadsheets were translated into English and Bechtel was asked to review each of these A detailed review of the spreadsheets appears in Appendix A

The major conclusion of our review of the Lietuvos Energia submittal was that it included very limited reporting for cost allocation to tariff categories This is a key element of the cost-of-service methodology and should be included in all submittals by service providers Most of our other major comments address both the submittal and NCC-approved methodology, as follows

- There does not appear to be an acceptable approach for determining a reasonable level of profit A "reasonable" rate of return on investment is the most commonly used criterion in instances where private capital is invested Cash flow criteria may also be appropriate for some Lithuanian service providers (The example presented in Appendix C, showing the integration of cost-based and incentive pricing approaches, illustrates these two alternatives to setting approval profit levels)
- Additional load research and/or metering is required to support the cost allocation process For example, it appears that the methodology does not accurately reflect the fact that lower voltage levels account for significantly higher losses per unit of sales Load research and/or metering would support a more equitable allocation of losses
- Many of the allocation formulas in the approved methodology could be replaced by directly-reported costs A detailed uniform system of accounts for reporting service provider costs should be developed, corresponding to the major cost elements of the power system

2 4 REVISED COST-BASED METHODOLOGY

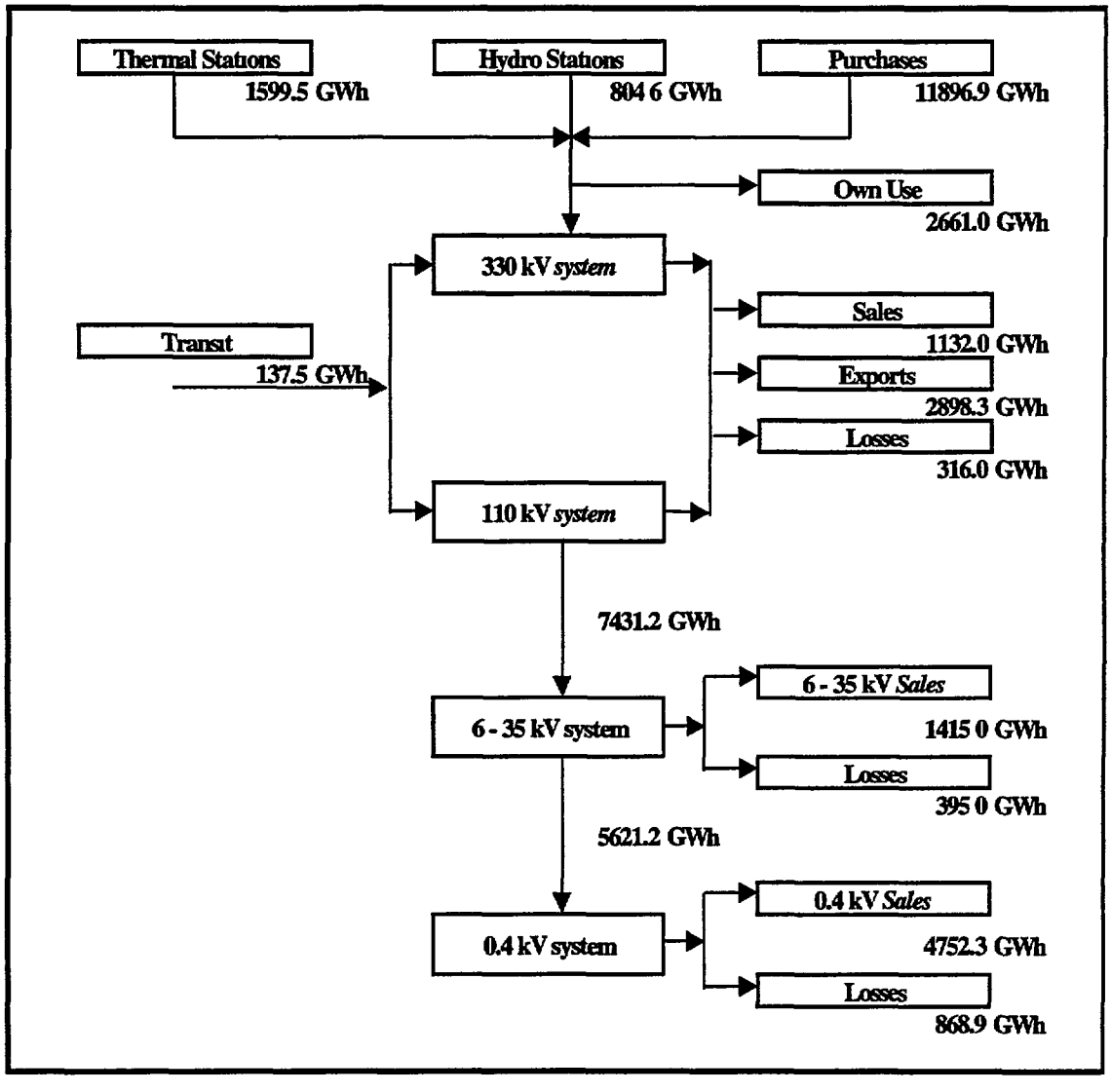
Based on the review of the Lietuvos Energia submittal, a revised methodology was developed that would improve forms for tariff calculations, and allow direct calculation and analysis of tariffs by customer class, voltage level, and time-of-use The methodology is described in detail in Appendix B and is based on an exogenously-set level of profit Two alternative methods of setting "reasonable" profit level are presented in the example in Appendix C The major steps in the methodology are

- Develop load data
- Develop energy balance and graphical presentation of energy flows
- Input and summarize system expenses by cost category
- Calculate cost based revenue requirements
- Distribute expenses by voltage level
- Calculate demand and energy tariffs by voltage level
- Calculate time-of-use tariffs
- Reconcile revenues
- Calculate marginal cost based revenues
- Compare marginal cost revenues with cost based revenues

2 5 LONG-RUN MARGINAL COST AND PROTECTION OF THE POOR

Figure 2-2 shows a calculated energy flow for the Lithuanian power system that was developed as part of the revised methodology discussed in Section 2 4 Assumptions are used to estimate losses by voltage level since current metering does not provide this information However, it is clear from the diagram that as customer voltage levels decrease, losses and investment-per-unit-of-sales increase If prices reflect costs, low-voltage customers will invariably pay higher prices This has become the case in Lithuania

Figure 2-2 Estimated Energy Flow in the Lithuanian Power System



The higher cost of service to residential customers is the major reason why cost-based pricing is resisted This is particularly true for low-income residential customers What is the proper regulatory approach for dealing with the economically disadvantaged?

The approach in Lithuania has been to treat energy just as any other critical commodity required for survival The welfare system provides payments to the those with low incomes if their energy bills reach a set level of their income In practical terms this applies only to heating The advantage of this approach is that it is economically sound (i e , prices are not distorted) and energy service providers and regulators do not have to duplicate a bureaucracy to keep track of income levels

However, under some circumstances, *lifeline tariffs* can be used to assist low-income consumers in a way that is economically sound Lifeline tariffs establish exceptionally low costs for subsistence usage levels and higher prices thereafter In effect, high-usage customers subsidize low-usage customers A key factor in determining the applicability of this approach is whether long-run marginal costs are greater or lower than financial costs as defined by a cost-of-service study

The cost-based approach in the current methodology and underlying the proposed revisions is based on recovering financial costs However, economic theory dictates pricing long-run marginal costs, often referred to as true economic costs If long-run marginal costs are higher than financial costs, pricing at this level produces excess revenue There are numerous ways to reconcile this situation, one of which is to use it as an opportunity to finance lifeline tariffs without charging any customer more than true economic cost On the other hand, if long-run marginal costs are lower than financial costs, the only way to finance lifeline tariffs would be to charge some customers more than true economic cost

What is case in Lithuania? The calculation of long-run marginal cost incorporates projections of future supply and demand The current situation is one of overcapacity If this situation were to continue into the future, long-run marginal cost would be low It is likely that the financial costs of operating the system would be greater than long-run marginal cost However, most supply is from the Ignalina plant Some scenarios for Ignalina would produce much higher long-run marginal costs Under such scenarios, it would be justifiable to charge long-run marginal cost for marginal usage to finance subsistence level usage

This situation shows a major difficulty in applying long-run marginal cost pricing to a system that is so dependent on a single source of supply Furthermore, the applicability of lifeline tariffs is questionable if the current approach of providing compensation to the poor through the welfare system is effective However, if perceptions of future supply and demand change significantly, it would be appropriate to revisit the question of lifeline tariffs

Section 3 presents an approach to integrating incentive measures with cost-based price regulation

Section 3 Incentive Price Regulation

3 1 OVERVIEW

Historically, the gas and electricity industries were considered monopolies and prices were heavily regulated The regulatory model used by power sectors that operated on a financially independent basis allowed for the reimbursement of "reasonable" costs as well as a "reasonable" rate of return on investment We refer to this as cost-based regulation

Recently, competition was introduced in gas production and electricity generation Gas wellhead prices were deregulated and electricity generation market approaches were introduced to the electric sector However, the natural monopoly characteristics of the transmission and distribution systems continue to persist Continued cost-based regulation of these areas is one alternative Incentive-based regulation is another regulatory model that has been applied to transmission and distribution Advocates of incentive regulation claim that it can provide better financial incentives for utilities to lower electricity costs and that is more flexible and market-based It is also often argued that incentive regulation can reduce regulatory oversight of the service provider planning process, allowing utilities to be cost-driven and customer-driven rather than regulator-driven

The fundamental principle behind incentive regulation is that good service provider performance should lead to higher profits, and poor performance should lead to lower profits While this general principle is widely accepted, regulators designing incentive regulation mechanisms will need to decide what "good service provider performance" consists of and how a ratemaking formula can be designed to link performance with profits

Traditional cost-based regulation involves basing prices on annual cost reviews One of its greatest shortcomings is that the service provider's incentive to reduce costs is severely limited because profit levels are not directly affected by costs The distinguishing characteristic of incentive regulation methodologies is that either prices or revenues for services are set at a fixed level for 3 to 5 years Cost reductions during the 3- to 5-year time period translate into greater profits, giving the service provider an incentive for more efficient operation After the 3- to 5-year time period, prices (or revenue levels) are reset to reflect the more efficient operation so that customers can benefit from lower prices over the long term

The most commonly discussed incentive regulation mechanism is the "price cap" Maximum prices in real terms are defined for each customer class, in the case of retail tariffs, or for particular types of service, such as high-voltage transmission A price cap scheme begins by setting the initial rates for each customer class fairly, based on an appropriate allocation of costs The price cap is then allowed to increase from year to year to allow for inflation, but is also required to decline over time to encourage increased productivity The generic price cap formula can be defined as

$$Price_{(t)} + Z_{(t)} \leq Price_{(t\ 1)} * (1 + I - X) + Z_{(t\ 1)}$$

where $Price_{(t)}$ is the maximum price that can be charged to a customer class (for retail tariffs) or for a particular service for the current period for services subject to the price cap, $Price_{(t\ 1)}$ is the

average price charged to the same class or classes during the previous period, "I" is the inflation factor, "X" the productivity improvement factor, and "Z" represents the contribution to price of any incremental costs that are not subject to the cap The costs not subject to the price cap mechanism can be regulated through cost-based approaches Cost-based approaches, including cost allocation, are commonly used in developing the base-year price cap

Revenue caps are based on the same principle as price caps – where the cap in one year is based on the previous year with adjustments for inflation and productivity – and can achieve many of the same objectives as price caps Its generic form is as follows

$$\text{Revenue}_{(t)} + Z'_{(t)} \leq \text{Revenue}_{(t\ 1)} * (1 + I - X) + Z'_{(t\ 1)}$$

where Revenue(t) is the maximum revenue to be collected from a given customer class (for retail tariffs) or for a particular service in a given period and Z't is the revenue to be collected to cover costs not subject to the revenue cap Once the revenue cap is set, prices are defined by projected sales Revenue caps provide significantly different incentives They tend to stabilize revenue to the service rather than price, however, they may be appropriate for regulating costs that are not sensitive to the level of sales

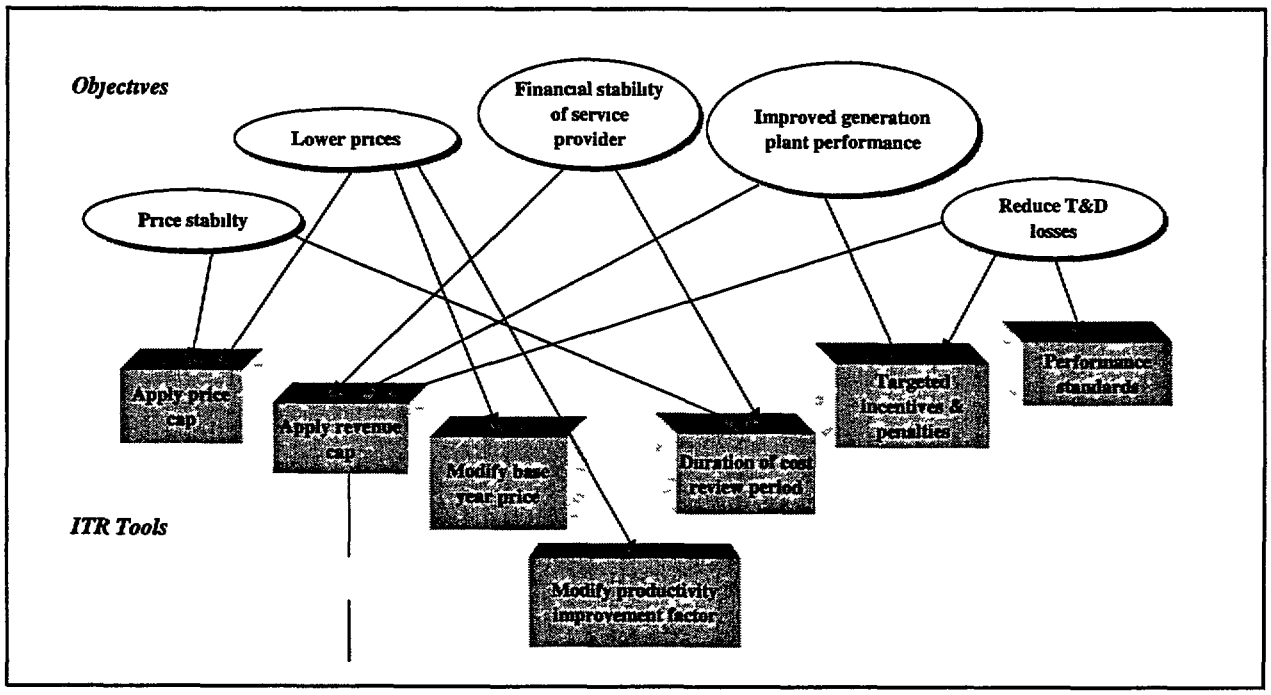
Another feature of most incentive regulation methodologies is that the service provider is generally given a certain amount of flexibility in pricing The price (or revenue) levels defined are maximum levels or caps Customer discounts are allowed as long as other customers stay at or below the maximum levels When applied properly, this allows the service provider to target customers that are particularly price sensitive and provide competitive prices if it is in its financial interest to do so The use of this feature requires clearly defined conflict-of-interest regulation For example, it is clearly against the public interest for a service provider to provide a discount to a subsidiary company to gain a competitive advantage If service providers and major portions of a customer class are state owned, as is the case in Lithuania, care would have to be taken in applying price flexibility since it could be used as a mask for state subsidies

Efficient operation and low costs are not the only objectives of energy regulation Regulators are also concerned about such issues as price stability, price equity, reliability, quality of service, promotion of energy efficiency, and environmental protection The incentives used to reduce costs under incentive regulation can potentially affect quality of service Targeted penalties, incentives, and performance standards have been used in conjunction with incentive regulation methodologies to address many performance-related issues

Figure 3-1 illustrates how incentive regulation methodologies can be tailored to regulatory priorities An often advertised potential advantage of incentive regulation methodologies is the reduced amount of regulatory oversight in comparison to cost-based methodologies However, Figure 3-1 shows that incentive regulation requires its share of regulatory involvement in methodology design and implementation Designing a incentive regulation mechanism to achieve any one particular objective can frequently require detailed analysis For example, setting an appropriate productivity performance index requires a complicated and sometimes contentious analysis of industry costs and operating trends Most incentive regulation mechanisms need to be reviewed over time to monitor their effectiveness, assess ratepayer and

shareholder impacts, and prevent unintended outcomes They then need to be modified where appropriate

Figure 3-1 Incentive Regulation Options for Meeting Various Regulatory Objectives



3 2 EXAMPLE

An example of how a integrated methodology with cost-based and incentive regulation elements could be applied to the Lithuanian power sector is presented in Appendix C A model of this methodology is contained in METHOD2 XLS, an Excel 97 spreadsheet Some of the key features of the methodology are that it

- Allows flexibility in the degree to which incentive regulation is applied to each accounting cost element For example, 20% of repair costs can be regulated through a revenue cap and 80% through a cost-based approach
- Separates generation/purchasing, transmission, and distribution elements of the power sector to accommodate future restructuring options This requires that there be an accounting separation of the generation/purchasing, transmission, and distribution functions of Lietuvos Energia
- Allows multiple generators and distributors

- Allows a dual generating/purchasing function for Lietuvos Energia, reflecting the current situation However, no changes in the basic approach are required should further divestment of generation assets be required of the generation purchaser

A revenue cap approach has been used for costs subject to incentive regulation This was done based on a judgment that these costs are largely insensitive to changes in demand and because the financial stability of Lietuvos Energia is a high regulatory priority The cost review period used for costs subject to incentive regulation was 3 years Some modifications to the spreadsheet would be required to accommodate a price cap approach or combination price/revenue cap as well as cost review periods of different durations

The excess generating capacity available from the Ignalina plant provides the potential for substantial export sales The margin (i e , revenues minus incremental generating and transmission costs) on these sales is an important factor in determining domestic tariffs Transit sales for transmission and heat sales by combined heat and power generators are also addressed

Figure 3-2 illustrates the major steps in the methodology In developing this example we used the 1997 Lietuvos Energia financial results available on their website Financial results for Ignalina NPP, Vilnius CHP, and Kaunas CHP were used based on a mid-1997 filing to NCC which projected costs for the year We further disaggregated Lietuvos Energia financial results to generation/purchasing, transmission, and seven distribution subsidiaries It is expected that future accounting requirements will provide this information directly

Other key assumptions in the example are

- Domestic sales will increase at an average of about 4% per year over the next 3 years
- Exports will be at the 3000 GWh level at a price of 6 ct/kWh in real terms and transit sales will be 150 GWh per year at a price of 1 ct/kWh
- The costs reported for providers of both heat and electricity were assumed to reflect the allocated cost of the electricity component Therefore, projected heat sales and price for the various CHPs were projected to be zero
- There were no projected subsidies to any of the service providers

Incentive regulation is only appropriate in situations where the service provider has control of costs For example, the cost of imported fuel is a poor candidate for incentive regulation because it is determined by the world market, and is beyond the control of the service provider (It may be advisable to have a portion of imported fuel cost under incentive regulation, say 10%, to act as a incentive for fuel efficiency) We also excluded the Ignalina plant for incentive regulation in the example It appears to us that the use of incentive regulation at Ignalina would require changes in the annual price approval process that now exists Furthermore, it strikes us that cost reduction at Ignalina is a low regulatory priority due to its already relatively low price and the importance of not providing any incentives that might be perceived to compromise safety or reliability

Figure 3-2 Overall Pricing Methodology

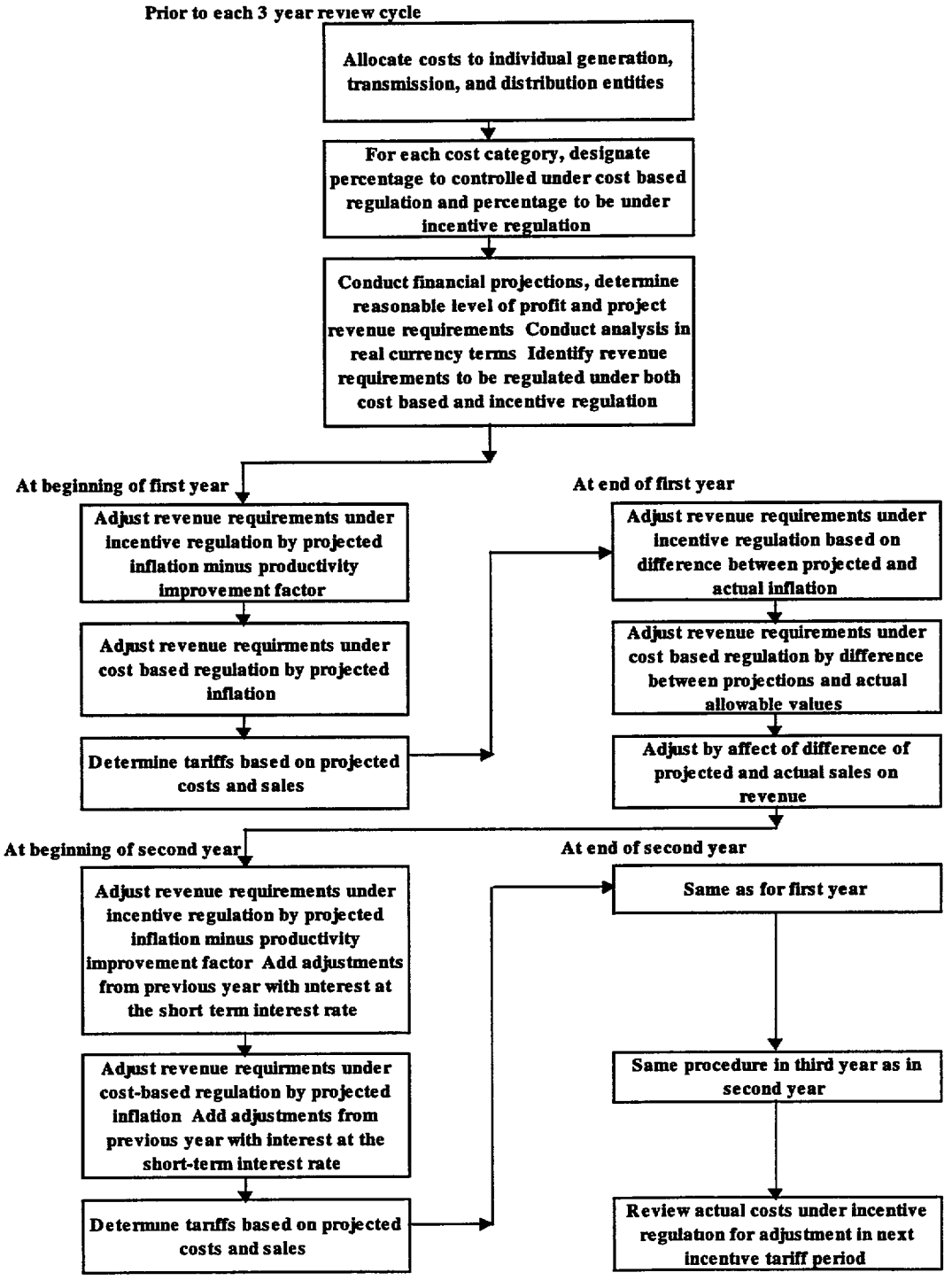
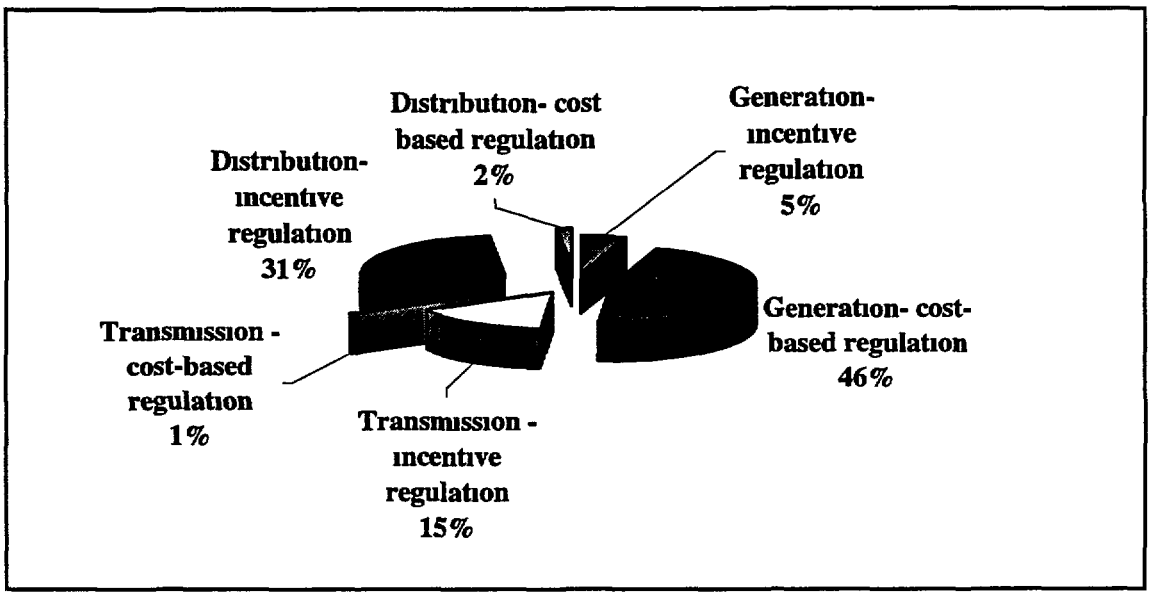


Figure 3-3 shows the distribution of costs in the first year of the example by cost area and regulatory approach Generation is the largest single cost area and is dominated by cost-based regulation because of Ignalina Incentive regulation applies to a much higher percentage of costs for transmission and distribution Overall it appears the incentive regulation could be applied to about 50% of total costs in the power sector

Figure 3-3 Regulatory Approach by Cost Area – Year 1



Appendix A Review of Methodology in 1997 Lietuvos Energia Submittal

The approved methodology for setting electricity prices is defined by "Methods for Calculation of Electrical Energy Prices (approved by the National Control Commission for Energy Prices and Energy Activities, Resolution No 8 of May 10 1996) A translated copy of the body of the resolution was provided to Bechtel in October 1997, though there are a number of appendices to the document that have not been translated This translated document is referred to as the Methodology in this appendix

In August 1997, Lietuvos Energia submitted a request for a tariff increase This request was supported by a forecast of revenue requirements and a series of calculations that allocated forecast costs into tariff categories These were translated to English and Bechtel was requested to review each of these These are referred to as the Revenue Requirements Model and the Allocation Model, respectively

The review of the two models The review is limited to methodological issues, both in terms of internal consistency and in terms of compliance with the Methodology The reasonableness of costs in the submittal are outside the scope of this review

A 1 REVIEW OF METHOD FOR REVENUE REQUIREMENTS FORECAST

A 1 1 Overall Comment

The original LE tariff submittal in August 1997 was accompanied by a revenue requirements forecast The spreadsheet provides a 3-year (1998 through 2000) projection of costs and a projection of the financial implications of a given scenario of average tariff increases over the 3-year period It is not clear how this scenario was derived

A 1 2 Cost Categorization

The Revenue Requirements Model categorizes costs into fixed common, variable common, fixed generation, variable generation, and transmission and distribution This categorization follows the general principles of the Methodology However, since the costs of transmission and distribution are not separated by voltage, there is inadequate data to develop tariffs by voltage level However, this is accomplished in the cost allocation model reviewed in Section 3 of this appendix

A 1 3 Profit and Loss

Pro forma profit and loss statements are prepared for the 3-year period based on the average tariff scenario At the level of average tariffs projected, LE shows a slight profit

A 1 4 Projection of Allowable Profit

The Methodology indicates that a "standard profit" will be determined by the Commission A table shows the following elements of the standard profit

- Compulsory allocations to the budget
- Profit at the company's disposition, including

- Allocations to the required reserves
- Allocations to other reserves
  - Asset insurance
  - Investment funds
- Dividends
- Annual bonus shares to members of the board
- Other allocations

The ratio of the standard profit to the fixed asset value of power plant and network minus accumulated depreciated is calculated, but does not appear to be the primary basis for determining its size

The Submittal provides a calculation of the standard profit based on an assumption of self-investment that appears to be approximately 40% However, it does not appear that this calculation enters into the projected tariff scenario

A 1 5 Fuel Costs

There are a number of formulas used for the calculation of fuel consumption These are not well documented nor is their rationale intuitively obvious It may be that the unexplained portions of the formulas are addressing allocations to heat and electricity and allocations among the fuels used a the CHP plants However, this is not clear

A 1 6 Cash Flow Analysis

Two cash flow scenarios are presented It does not appear that these are required by the Methodology The first cash flow projection serves to illustrate that the profit levels shown in the profit and loss statement are inadequate to support the investment plan projected The second cash flow projection is based on the same investment plan It includes a combination of increased debt financing and a policy of no dividend payment to balance cash outlays The increased debt financing also serves to decrease taxes on profits

A 1 7 Retail Tariffs

The existing tariff structure is as follows

1 Residential customers

1 1 Delivery at 0 4 kV

1 1 1 One-part tariff
1 1 2 Time-of-use tariff

1 2 Delivery at 6-10 kV

1 2 1 One-part tariff
1 2 2 Time-of-use tariff

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1 3 Special discount- Consumption greater than 12,000 kWh per year

2 Other customers

2 1 Delivery at 0 4 kV

2 1 1 One-part tariff
2 1 2 Time-of-use tariff (2 time periods)
2 1 3 Two-part tariff
2 1 4 Time-of-use tariff (4 time periods)

2 2 Delivery at > 6 kV and <110 kV

2 2 1 One-part tariff
2 2 2 Time-of-use tariff (2 time periods)
2 2 3 Two-part tariff
2 2 4 Time-of-use tariff (4 time periods)

2 3 Delivery at 110 kV and higher

2 3 1 One-part tariff
2 3 3 Two-part tariff
2 3 3 Time-of-use tariff (4 time periods)

The Methodology addresses the development of cost-based tariffs by voltage level and the estimation of costs by time of use The submittal only addresses average tariffs for residential and other customers (As discussed above, the tariffs in the submittal do not appear to be related to cost factors) Voltage level and time-of-use factors are not addressed in the submittal

A 2 REVIEW OF THE COST ALLOCATION MODEL

The LE cost allocation model (referred to as the Allocation Model) took the revenue level projection and allocated them to tariff categories It is our understanding that the Allocation Model was not originally part of the submittal, but was provided upon request

Comments on the Cost Allocation model are as follows

- The Allocation Model addresses critical elements of cost allocation and should be an integral part of the tariff submittal filings
- The Allocation Model generally follows the electric energy pricing methodology The calculation of the total income and the customer differentiation by voltage level is done according to the methodology The model also correctly assigns portion of the transmission and distribution costs to each voltage level (as described in the Methodology)
- The tariff methodology requires tariff differentiation according to the hours of electricity use into three periods light, medium and heavy load usage It appears that the Allocation Model develops the same three time periods according to the presented load curves and not according to the predetermined time intervals

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- There was an attempt to approximate the results of the production simulation model in the Methodology by analyzing the effect of shifting a production from a peak to an off-peak period It is not clear if this part of the Methodology was addressed in the Allocation Model There are analytical advantage for both the Methodology and the Allocation Model using production simulation model However, this would require development and agreement upon simulation assumptions
- It is not clear if the Allocation Model calculates the consumer fee introduced in the Methodology
- The Allocation Model introduces a correction factor accounting for the yearly inflation It appears that this factor is not discussed in the Methodology
- Consumption at each voltage level is an input to the Allocation Model The Allocation Model introduces *capacity* and *economy* categories of consumption at each voltage level These categories are not described in the Methodology, and it is not clear how are they derived

A 3 ADDITIONAL COMMENTS ON THE PRICING METHODOLOGY

Additional comments are as follows

- The Methodology predetermines the share of costs assigned for three transmission and distribution levels It would be more appropriate if these costs were developed by the service provider based on actual costs
- It is not clear how the transmission and distribution losses are accounted for in the Methodology

Future development and implementation of the methodology should also include

- Assure that the pricing methodology takes into account load research data (e g , peak load responsibility factors for allocating costs to customer classes)
- Update the depreciation and decommissioning accounts The amount of depreciation has to be adjusted to reflect inflation, and the regulators should verify that the depreciation reserve is adequate to replace facilities only and not used to fund operation and maintenance (O&M) costs The decommissioning fund should reflect an adequate amount to return the nuclear plant site to its original status when the plant is retired
- Calculate total expenses, develop costs and pricing for the INPP in a similar fashion as for the rest of the system, adding expenses such as wages, benefits, materials for maintenance and repairs, decommissioning, and depreciation To calculate depreciation accurately, work is needed in reevaluating the plant fixed assets
- Develop the pro forma financial statements (including income statements, balance sheets, and sources and application of funds) and present them to the regulators Summarize the financial parameters for each service provider to ensure the company's financial health

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Appendix B Methodology for Developing Cost-of-Service

B 1 INTRODUCTION

Based on our review of the Lietuvos Energia submittal (presented in Appendix A), we have developed a revised approach to revenue requirements projection and cost allocation This is presented here in Appendix B

Electricity prices should send proper economic signals to customers to help them make proper economic decisions The methodology presented below follows this concept, and tariffs are structured in the same fashion The proposed approach is summarized in an accompanying Excel spreadsheet containing formulas and all details of the methodology

B 2 DEVELOP LOAD DATA

The first step is to develop load data that would allow appropriate cost allocation according to voltage levels and customer groups We started with the available load data, and were data was unavailable made some estimates to develop the required information Load input data and analysis is presented in Table B-1

The steps in load analysis were

- Estimate peak and off-peak load
  - Define time-of-day periods
  - Estimate and separate consumption to time-of-day periods
  - Assign losses to voltage levels
  - Assign coincidence peak contributions for each voltage level

All these load analysis steps are essential in developing cost based tariffs reflecting time and point of energy use

B 3 DEVELOP ENERGY BALANCE

The energy balance was developed starting with gross plant generation and electricity purchases Total amount of generation was reduced to account for station own use and was adjusted for transits Next step was to develop sales and losses at each voltage level Information was available for total system losses and sales, and but not for losses or sales at each voltage level We had to estimate losses and sales by voltage levels and develop system balance by voltage level In addition, we anticipated the possibility of having two different low voltage (0 4 kV) tariffs, one for residential, and one for other customers In order to accomplish this analysis, we made an estimate of these sales In future, it would be desirable for this information could be obtained by direct measurements at the system The energy balance is presented in Table B-2 and in graphical form in Table B-3

Table B-1 Load Data and Analysis

Load Data for 1997					
Sales (GWh)			7299 3		
Peak Load (MW)			1200 est		
Shoulder Load (MW)			1000 est		
	0 4 kV (Residential)	0 4 kV (Other)	6 - 35 kV	110 kV	Total
Consumption (GWh)					
Peak Period	328	623	283	226	1460 est
Shoulder	656	1245	566	453	2920 est
Off-Peak	656	1245	566	453	2920 est
Total	1639	3113	1415	1132	7299
Distribution of Losses					Total
at 110 kV	71	135	61	49	316
at 6-35 kV	105	199	91		395
at 0 4 kV	300	569			869
Total Production	2115	4016	1567	1181	8879
Percentage of 110 kV	22%	43%	19%	16%	100%
Percentage of 6-35 kV	27%	50%	23%		100%
Percentage of 0 4 kV	34%	66%			100%
Note Used for allocating variable costs by voltage level					
Coincidence Peak (MW)					
Peak (MW)	432	516	192	60	1200
Percentage of 110 kV	36%	43%	16%	5%	100% est
Percentage of 6-35 kV	38%	45%	17%		100%
Percentage of 0 4 kV	46%	54%			100%
Note Used for allocating fixed costs by voltage level					

Table B-2 Energy Balance Data

		1997 data (projected) GWh	
1	Gross Generation	14301 0	1 1 1 4
1 1	Ignalina	11509 9	
1 2	Hydro	804 6	
1 3	Vilnius CHP	342 0	
1 4	Kaunas CHP	45 0	
1 5	Thermal power plants	1599 5	
2	Own Use	2661 0	
	Saldo of transit service	137 5	
3	Net Generation	11777 5	1 -2
4	Network losses	1579 9	
4 1	330-110 kV system - 20%	316 0	est
4 2	35-6 kV system - 25%	395 0	est
4 3	0 4 system - 55%	868 9	est
5	Exports (from 330 kV system)	2898 3	
6	Total delivery to 330-110 kV system	8879 2	3 -5
6 1	Losses at the 330-110 kV system	316 0	
6 2	Sales	1132 0	
7	Delivery to 35-6 kV system	7431 2	6-6 1-6 2
7 1	Losses at the 35-6 kV system	395 0	
7 2	Sales	1415 0	
8	Delivery to 4 kV system	5621 2	7-7 1-7 2
8 1	Losses at the 4 kV system	868 9	
8 2	Delivered to customers	4752 3	8-8 1-8 2
8 3	Sales to Residential Customers	1639 2	
8 4	Sales to Other Customers	3113 1	
	Difference	0 0	8 2-8 3-8 4
	Sales to Other Customers	5660 1	
	330-110 kV system - 20%	1132 0	est
	35-6 kV system - 25%	1415 0	est
	0 4 system - 55%	3113 1	est

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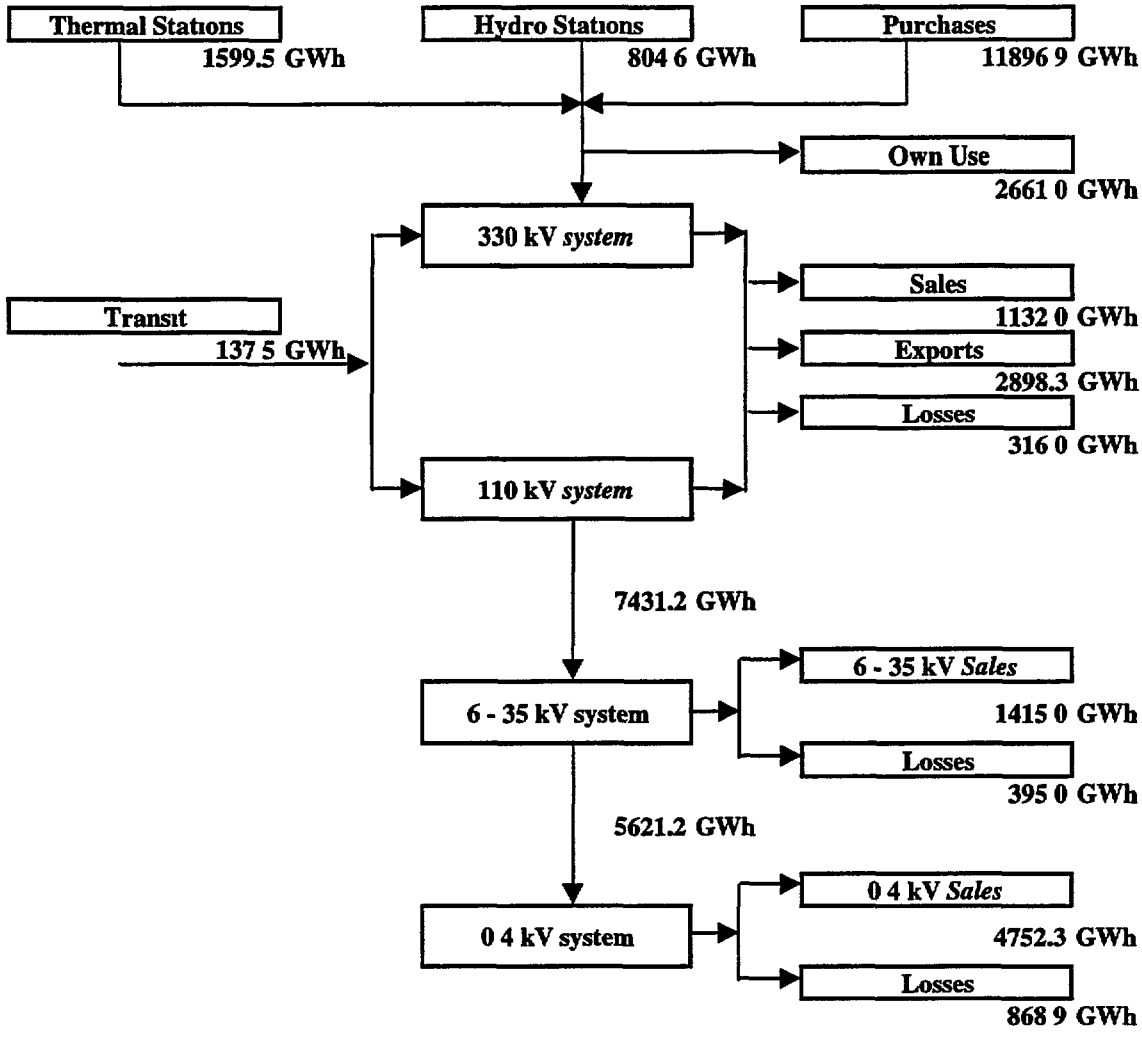
Table B-3 Energy Flow



B 4 MAKE INPUTS AND SUMMARIZE SYSTEM EXPENSES BY COST CATEGORIES

The next step was to summarize expense inputs from tariff submittal into categories This process is also known as cost functionalization allocates expenses as fixed and variable in the following categories system costs, generation costs, transmission and distribution costs, and purchased energy costs (see Table B-4) Based on the submittal, several questions were raised that the Commission and the service provider should discuss in the course of submittal review

- Are system costs truly representative of general system costs?
- How should the power purchase costs best be represented in this format?
- How should the costs be separated into transmission and distribution functions?

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Table B-4 System Expense Information

System Costs				
1 Variable Costs		thousand Lt	1 1 to 1 9	23371
1 1 Water			0	
1 2 Purchased Energy			0	
1 3 Repair Expenses			1595	
1 4 Materials and Supplies			0	
1 5 Mission Expenses			0	
1 6 Office Service Expenses			0	
1 7 Transit			6322	
1 8 Expenses of other companies service-total			9375	
1 9 Other not mentioned expenses (?)			6079	
2 Taxes		thousand Lt	2 1 to 2 7	9210
2 1 Asset Tax			106	
2 2 Earth Rent Tax			25	
2 3 Road Tax			7718	
2 4 Natural Resources			0	
2 5 Pollution Tax			0	
2 6 VAT (difference) (?)			0	
2 7 Asset Insurance			1361	
3 Fixed Costs (Including Taxes)		thousand Lt	6 1 to 6 5	79629
3 1 Import expenses			0	
3 2 Depreciation			2425	
3 3 Salaries			5750	
3 4 Social security (insurance)			1725	
3 5 Interest on credits			60519	
3 6 Taxes (2)			9210	

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Table B-4 System Expense Information (Cont'd)

Generation Costs			
4 Variable Costs	thousand Lt	3 1 to 3 9	44382
4 1 Water		1509	
4 2 Purchased Energy		203	
4 3 Repair Expenses		34063	
4 4 Materials and Supplies		5048	
4 5 Mission Expenses		125	
4 6 Office Service Expenses		52	
4 7 Transit		0	
4 8 Expenses of other companies service-total		2254	
4 9 Other not mentioned expenses (?)		1128	
5 Taxes	thousand Lt	4 1 to 4 7	9932
5 1 Asset Tax		4114	
5 2 Earth Rent Tax		590	
5 3 Road Tax		298	
5 4 Natural Resources		497	
5 5 Pollution Tax		4385	
5 6 VAT (difference) (?)		48	
5 7 Asset Insurance		0	
6 Fixed Costs (Including Taxes)	thousand Lt	7 1 to 7 5	78632
6 1 Import expenses		0	
6 2 Depreciation		31500	
6 3 Salaries		25800	
6 4 Social security (insurance)		8000	
6 5 Interest on credits		3400	
6 6 Taxes		9932	

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Table B-4 System Expense Information (Cont'd)

Transmission and Distribution Costs				
7	**Variable Costs**	thousand Lt	5 1 to 5 12	159567
7 1	Electric Energy		5951	
7 2	Water		411	
7 3	Purchased Energy		1424	
7 4	Repair Expenses		84714	
7 5	Materials and Supplies		28371	
7 6	Meter Changing Expenses		19992	
7 7	Reducing Losses		0	
7 8	Mission Expenses		726	
7 9	Office Service Expenses		601	
7 10	Transit		0	
7 11	Expenses of other companies service-total		10326	
7 12	Other not mentioned expenses (?)		7051	
8	**Taxes**	thousand Lt	6 1 to 6 7	28153
8 1	Asset Tax		26425	
8 2	Earth Rent Tax		390	
8 3	Road Tax		613	
8 4	Natural Resources		0	
8 5	Pollution Tax		260	
8 6	VAT (difference) (?)		251	
8 7	Asset Insurance		214	
9	**Fixed Costs (Including Taxes)**	thousand Lt	8 1 to 8 5	239853
9 1	Import expenses		0	
9 2	Depreciation		89200	
9 3	Salaries		94100	
9 4	Social security (insurance)		28400	
9 5	Interest on credits		0	
9 6	Taxes		28153	

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Table B-4 System Expense Information (Cont'd)

	Purchased Energy Cost			
9	**W/O Fuel (Fixed Cost)**	thousand Lt	9 1 to 9 3	375191
9 1	Ignalina		361140	
9 2	Vilnius CHP		9898	
9 3	Kaunas CHP		4153	
10	**Fuel Price**			
10 1	- 1 ton of heavy fuel oil	Lt/t	346	
10 2	- 1000m3 natural gas	Lt/1000m3	335	
10 3	- other fuels (orimulsion)	Lt/t	216	
	- nuclear fuel	ct/kWh	2 26	
11	**Purchased energy**	mil kWh		
11 1	from Ignalina NPP		10421	
11 2	from Vilnius CHP		247	
11 3	from Kaunas CHP		41	
11	**Export Price**	Lt/kWh	8 15	
12	**Fuel Used**			
12 1	-natural heavy fuel oil	1000 t	215	
12 2	-natural gas	mil m3	95	
12 3	-other fuel sorts (orimulsion)	1000 t	38	
	Fuel Cost/kWh	thousand Lt		
	Ignalina		2 26	
	Vilnius CHP		6 7	
	Kaunas CHP		7 4	
	Fuel Cost	thousand Lt		
	for purchased electricity			
	Ignalina		235520	
	Vilnius CHP		16549	
	Kaunas CHP		3034	
	other fuels			
	-natural heavy fuel oil		74242	
	-natural gas		31879	
	-other fuel sorts (orimulsion)		8258	
	Total		369481	

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B 5 CALCULATE COST-BASED REVENUE REQUIREMENTS

After summarizing system expenses, we built a service provider revenue requirement that accounts for export revenues, profits, VAT and government duty (see Table B-5) The level of profit was taken directly from the submittal and was not verified against the investments or other system requirements This analysis will be performed in the process of developing an incentive tariff methodology

Table B-5 Revenue Requirement Calculation

		GWh	
1	**Sales**	10197 6	
1 1	Sales to Other Customers	5660 1	
1 2	Sales to Residential Customers	1639 2	
1 3	Exports (from 330 kV system)	2898 3	
	Costs	thousand Lt	
2	**Fixed Costs**		
2 1	System	78268	
2 2	Generation	78632	
2 3	Transmission and Distribution	239853	
2 4	Purchased Power	375191	
3	**Variable Costs**		
3 1	System	23371	
3 2	Generation	44382	
3 3	Transmission and Distribution	159567	
3 4	Fuel Costs	369481	
	Total System Costs	1368745	
	Revenues from Exports	236088	
	System Costs after Exports	1132657	
	Profit (Including Tax)	100000	
	Percentage of System Costs	8 83%	
	VAT	186747	
	Government Duty	12327	
	Revenue Requirements	1431731	
	Average Tariff (ct/kWh)	19 6	
	Transmission and Distribution Cost Allocation		
		Fixed	Variable
	110 kV (32%)	76753	51061
	6 - 35 kV (32%)	76753	51061
	0 4 kV (36%)	86347	57444

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B 6 DISTRIBUTE EXPENSES BY VOLTAGE LEVEL

Distribution of transmission and distribution expenses by voltage level was done according to the service provider allocations As shown in Table B-6, 32% of expenses was allocated to high voltage levels (110 kV and above), 32% was allocated to medium voltages (6-35 kV), and the remaining 36% was allocated to low voltage distribution network

Allocation of expenses for general system function, for generation, purchases, and fuel was done according to consumption including losses at each voltage level The most important question in the allocation process is how to allocate cost of Ignalina NPP, and revenues from the sales of electricity For this analysis we used the same allocation between the fixed and variable costs as was presented in the submittal Revenues from the sales of electricity were also allocated in the same proportion However, this issue require more analysis by the Commission

Based on allocation of expenses, we calculated costs for unit of consumption at each voltage level Fixed costs were represented as demand charges, while variable cost are represented as energy charges Costs were also calculated for the case when all costs are rolled into the energy charge

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Table B-6 Allocation of Costs by Voltage Level

Allocate Costs by Voltage Level (thousand Lt)

Costs

		Fixed	Variable	
	System	78268	23371	
	Generation	78632	44382	
	Purchases and Fuel	232294	276290	
	110 kV (32%)	76753	51061	
	6 - 35 kV (32%)	76753	51061	
	0 4 kV (36%)	86347	57444	
	Total Cost	629047	503610	1132657

Cost Allocation

		Fixed	Variable	
For 110 kV				
	System	3913	3625	
	Generation	3932	6883	
	Purchases and Fuel	11615	42849	
	110 kV (32%)	3838	7919	
	6 - 35 kV (32%)	0	0	
	0 4 kV (36%)	0	0	
	Total	23297	61275	84573
For 6-35 kV				
	System	12523	4531	
	Generation	12581	8604	
	Purchases and Fuel	37167	53561	
	110 kV (32%)	12280	9899	
	6 - 35 kV (32%)	12927	11716	
	0 4 kV (36%)	0	0	
	Total	87478	88310	175788
For 0 4 kV (Other)				
	System	33655	9967	
	Generation	33812	18928	
	Purchases and Fuel	99887	117834	
	110 kV (32%)	33004	21777	
	6 - 35 kV (32%)	34741	25774	
	0 4 kV (36%)	46999	37630	
	Total	282097	231911	514008
For 0 4 kV (Residential)				
	System	28176	5248	
	Generation	28308	9967	
	Purchases and Fuel	83626	62046	
	110 kV (32%)	27631	11467	
	6 - 35 kV (32%)	29085	13572	
	0 4 kV (36%)	39348	19814	
	Total	236174	122114	358288
	Total Cost			1132657

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B 7 CALCULATE DEMAND AND ENERGY TARIFFS BY VOLTAGE LEVEL

The next step was to calculate tariffs by voltage level – including not only costs but also profits, VAT, and government duty Tariffs are presented in Table B-7

Table B-7 Demand and Energy Tariffs by Customer Class

	Demand (Lt/kW-year)	Energy (c/kWh)	Demand Rolled into Energy
110 kV	491	6 84	9 44
6-35 kV	576	7 89	15 70
0 4 kV (Other)	691	9 42	20 87
0 4 kV (Residential)	691	9 42	27 63

Note Tariffs include cost-of service, profit, excise duty, and VAT

B 8 CALCULATE TIME-OF-USE TARIFFS

Tariffs were further divided into time-of-use tariffs based on estimated demand charge allocation by time-of-use (Table B-8) We defined three time periods (peak, shoulder, and off-peak) and estimated distribution of demand charge to each time period Defining appropriate time periods and demand allocation requires further analysis by the service provider and the Commission tariff experts As part of the analysis, we also made reconciliation of revenues using both methods to verify that they satisfy service provider required revenues

Table B-8 Time-of-Use Tariffs

	Assigned Demand Charge	110 kV	6-35 kV	0 4 kV (Other)	0 4 kV (Residential)
Peak Period	60%	14 65	31 33	43 78	64 05
Shoulder	30%	8 79	13 75	18 01	23 08
Off-Peak	10%	7 49	9 84	12 28	13 97

Note Demand charge rolled into energy tariffs

B 9 CALCULATE MARGINAL COST-BASED REVENUES

As the last step, we calculated service provider revenues using marginal cost pricing method For this example we used marginal cost prices from an earlier tariff study of the Lithuanian power system (Lithuania Energy Pricing Study, by Kennedy and Donkin Power, 1994) Since the Lithuanian power system has some unique characteristics, this exercise was performed to compare cost-based revenues with marginal cost-based revenues (Table B-9)

The results show that current over-capacity, both in generation and transmission capabilities, would result in low additional operational and investment costs to satisfy marginally increased consumption This lower marginal costs result in much lower marginal cost based tariffs, and lower service provider revenues

Table B-9 Marginal Cost Pricing and Revenues

Marginal Costs					
Exchange Rate (Lt/$)	4 00				
	Generation	330 kV	110 kV	6-35 kV	0 4 kV
Peak Period	1 43	1 45	1 50	1 56	1 64
Shoulder	1 00	1 02	1 05	1 09	1 15
Off-Peak	1 00	1 02	1 05	1 09	1 15
In Lithuanian c/kWh					
	Generation	330 kV	110 kV	6-35 kV	0 4 kV
Peak Period	5 72	5 80	6 00	6 24	6 56
Shoulder	4 00	4 08	4 20	4 36	4 60
Off-Peak	4 00	4 08	4 20	4 36	4 60
Note Marginal Costs from Kennedy & Donkin Power Tariff Study - Scenario A (US c/kWh)					
Revenues Using Marginal Costs (thousand Lt)					
		110 kV	6-35 kV	0 4 kV (Other)	0 4 kV (Residential)
Peak Period		13584	17660	40843	21506
Shoulder		19018	24678	57280	30161
Off-Peak		19018	24678	57280	30161
Total Revenues					**355868**

Appendix C Methodology Incorporating Incentive Pricing – Electricity Example

Objective

To provide the Lithuanian National Control Commission of Prices for Energy Resources and of Energy Activities in Lithuania (NCC) with a realistic example of how to apply incentive regulation to the electricity power sector

INTRODUCTION

Cost-based tariff methodologies focus on reimbursing energy service providers with some combination of projected and actual costs Such methodologies are a significant improvement over tariff-setting based primarily on political and social considerations However, they have the shortcoming that they do not provide financial incentives to service providers to reduce costs

Incentive methodologies provide such incentives in the following way tariffs are set at a constant level in real terms, or some modification thereof, for a period of several years The service provider is then allowed to retain the profits if costs can be decreased during this time Conversely, the service provider will have reduced profits if costs cannot be contained

Some important questions that should be considered in applying incentive tariffs include

- What sort of costs are best controlled by incentive regulation?
- What time period should be used between reviews of costs covered under incentive regulation?
- What is the appropriate form of incentive regulation?

Incentive regulation- Applied to costs that can be controlled

The costs that are best regulated under an incentive tariff scheme are those which are to some degree under the control of the service provider Investment and labor costs both fall under this category However, fuel costs are often driven by factors far outside the control of individual service providers are generally not good candidates for regulation under incentive tariffs

Cost review period- Minimum of three years

Difficult to regulate on price if sales are highly uncertain

The time period for tariff review under incentive tariffs must be long enough for service providers to implement cost-saving measures and realize some benefit from them On the other hand, the longer the review period the greater the impact of setting the incentive tariff at the "wrong" level This is particularly important in times of volatile costs or when underlying costs are not well understood Five years has been typical for the review period for incentive electricity tariffs in the UK Three years represents about the minimum length of the review period

Most applications of incentive tariff methodologies focus on keeping prices at a constant real level and are referred to as "price cap" methodologies However, during times of significant economic

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uncertainty, a "price cap" approach can result in volatile revenue levels for the service provider due to uncertainty in future sales In such a situation, an incentive methodology can focus on maintaining revenue levels This is referred to as a "revenue cap" approach

This appendix shows the application of an incentive methodology in the Lithuanian electric power sector We feel that an incentive methodology is appropriate for only some of the costs experienced in the Lithuanian power sector The example presented shows how cost-based and incentive regulation can both be utilized to reflect the differences in control the service providers have over various types of costs

A three-year review period is used in the example In part this has been done to reduce the size of the example However, we think that this may be an appropriate review period for an initial implementation of incentive price regulation given some of the cost uncertainties in the sector The example shows all entities entering a three-year review period at the same time In practice, this would probably not be done, if for no other reason than to level of workload of regulatory personnel

The example also uses a "revenue cap" approach This approach was used based on discussions with the NCC concerning uncertainties over future electricity demand

The example is presented in an Excel spreadsheet (METHOD2 XLS) Tables in this appendix are excerpts from this spreadsheet Each table is followed by a hyperlink to the appropriate part of the spreadsheet to assist those you may want to study the spreadsheet and report together (Contents of Electricity Methodology Spreadsheet)

THE LITHUANIAN POWER SECTOR

The Lithuanian supply system has undergone a number of organizational changes over the past few years and future changes are planned At present there are three separate generating companies that sell to Lietuvos energia (LE) which operates some generating capacity as well, makes all international purchases and exports, operates the high voltage (110 and 330 kV) transmission system, and the distribution system There are seven distribution subsidiaries This structure is shown in Figure C-1

Ignalina Nuclear Power Plant (NPP) is the largest generating source at 2x1300 MW and is 100% state-owned, It is much larger that the needs of the country, with a domestic peak load of about 1200 MW Ignalina produces over 90% of the energy requirements of the country with spare capacity for export

LE is a joint stock company (86% state-owned and 14% privately owned in 1997) The Kruonis Pumped Storage Plant provides regulation

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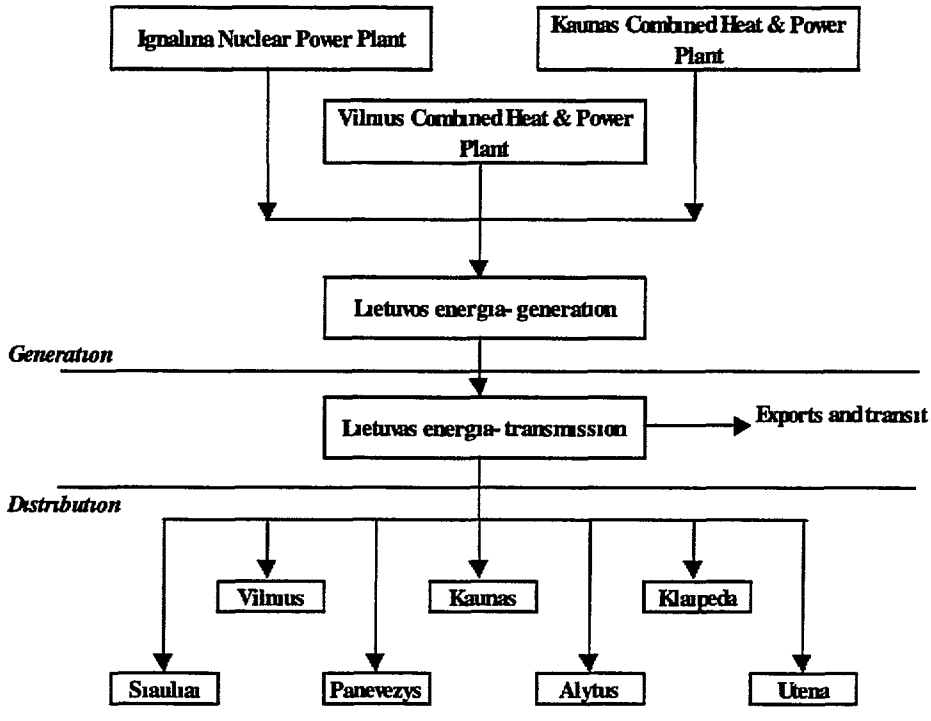
on the system The large size of the Ignalina units with respect to system size results in large reserve requirements The 1800 MW Lithuanian Power Plant provides a major portion of this reserve LE also operates the Kaunas Hydro Plant (400 MW) and the Mazeikiai CHP which serves the Mazeikiai Oil Refinery

Vilnius Combined Heat & Power (CHP) and Kaunas CHP are operated as separate municipally-owned companies Their operation is necessary for hear supply Their high incremental cost in comparison with Ignalina causes their electricity output to be limited to what is compatible with CHP operation

Figure C-1- Lithuanian Power Sector



NCC has full authority for developing retail prices for electricity and for approving prices from independent CHPs However, the responsibility for pricing of Ignalina power is somewhat less focussed Transactions in 1997 between Ignalina NPP and LE are based on Power Sale and Purchase Agreement signed by the parties in 1997 An agreement for sales in 1998 was signed by the parties in January Pursuant to the Agreement, the Lithuanian Government issues a decree approving the average purchase price for the year The Ministry of Economics issues a quarterly decree approving differentiated purchase prices and providing

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for the purchase by LPC of all power produced by Ignalina NPP The purchase price is further approved by the Minister of Economy and finally, the NCC

THE OVERALL METHODOLOGY

The overall methodology, combining cost-based and incentive approaches is illustrates in Figure C-2

Incentive pricing based on 3-year financial projections

Pricing projected for each year based on incentive component, adjusted for inflation, and other projected costs

Errors in projecting inflation, sales and non-incentive costs corrected each year

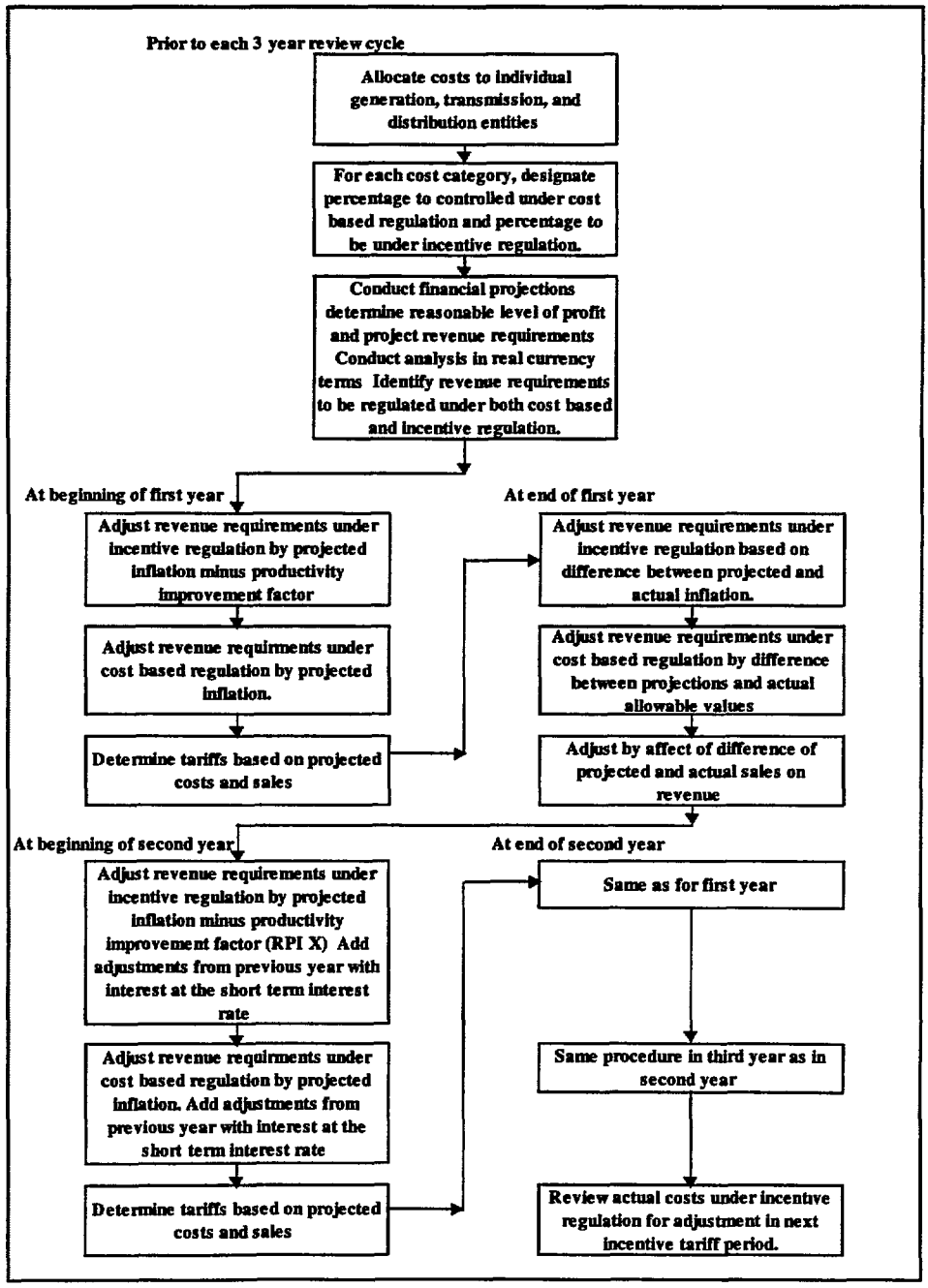

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Figure C-2 Overall Methodology

Some of the key features of the methodology are

- Requires that there be an accounting separation of the generation/purchasing, transmission and distribution functions of LE This is in line with plans that are underway and are required for membership in the European Union
- Allows multiple generators and distributors
- Allows a dual generating/purchasing function for LE, reflecting the current situation However, no changes in the basic approach are required should further divestment of generation assets be required of the generation purchaser
- Allows variations in the degree that incentive pricing be applied This can be done by cost category to reflect such factors as the degree of control that a service provider has over a particular type of cost This variation can also be applied to a service provider as a whole to reflect the different degrees of authority that NCC may have over the pricing of various service providers

The review cycle for costs under incentive regulation in the example is three years However, only slight changes to the METHOD2 XLS worksheet are required to accommodate review cycles up to five years

Revenues for exports are accounted for as negative costs of LE generation and transmission Transit sales are accounted for as negative costs of the transmission system If the costs reported by CHPs include the costs associated with heat production, the heat revenues count as negative costs of CHP providers Any projected subsidies are accounted for as negative costs for purposes of tariff calculation

THE EXAMPLE

We have developed a realistic example of how this methodology could be applied in Lithuania In developing this example we used LE financial results for 1997 presented in International Accounting Standards Financial results for Ignalina NPP, Vilnius CHP, and Kaunas CHP were based on a mid 1997 filing to NCC which projected costs for the year

We further disaggregated LE financial results to generation/purchasing, transmission, and to seven distribution subsidiaries The assumptions used in this disaggregation are shown in the METHOD2 XLS spreadsheet (1997 Financial Results), however, it is expected that in the actual application of the methodology, accounting data will be available for the individual entities Tariffs were estimated by voltage level Assumptions were made to convert sales data by customer category to voltage-level sales (Transformation of Customer Categories to Voltage-Level Sales)

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The key assumptions in the example are

- Domestic sales will increase at an average of about 4% per year over the next three years (Projected Retail Sales)
- Exports will be at the 3000 GWh level at a price of 6 ct/kWh in real terms and transit sales will be 150 GWh per year at a price of 1 ct/kWh (Projected Exports/ Transit Sales , Projected Export/Transit Price)
- The costs reported for providers of both heat and electricity were assumed to reflect the allocated cost of the electricity component Therefore, projected heat sales and price for the various CHPs were projected to be zero (Projected Heat Sales, Projected Heat Price)
- There were no projected subsidies to any of the service providers (Projected subsidy)

DESIGNATION OF REGULATORY APPROACH BY COST CATEGORY

It is possible to designate how each cost category is to be regulated It can be subject to cost-based (i e , cost-reimbursable and reviewed on an annual basis), contribute to an incentive level, or some combination The assumptions used in the example are shown in Table C-2 for LE generation, transmission and distribution Assumptions were also made for independent generators, but not shown in the table because of space considerations

(Note Values shaded gray in the tables presented in the hard-copy versions of this appendix represent input requirements)

Table C-2 Allocation of Costs to Cost-based and Incentive Regulation

Regulation Type

Independent generators
Ignalina NPP
Vilnius CHP
Kaunas CHP

	Generation		Transmission		Distribution	
	LE					
Cost Categories	% Incentive based	% Cost based	% Incentive based	% Cost based	% Incentive based	% Cost based
Fuel	0%	100%	0%	100%	0%	100%
Purchased Power	0%	100%	0%	100%	0%	100%
Labor	100%	0%	100%	0%	100%	0%
Social security	100%	0%	100%	0%	100%	0%
Materials and supplies	100%	0%	100%	0%	100%	0%
Repairs and maintenance	100%	0%	100%	0%	100%	0%
Depreciation	100%	0%	100%	0%	100%	0%
Taxes (except income tax)	0%	100%	0%	100%	0%	100%
Other expenses	100%	0%	100%	0%	100%	0%
Interest on debt	100%	0%	100%	0%	100%	0%
Provision for doubtful accounts	100%	0%	100%	0%	100%	0%
Gross profit	100%	0%	100%	0%	100%	0%
Adjustments						
Heat sales	0%	100%				
Export electricity/transit sales	25%	75%	25%	75%		
Subsidies	0%	100%				

A particular cost category can be partly cost reimursible with the remainder subject to incentive regulation

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Some examples will be discussed to illustrate how this can be applied If NCC judges that fuel costs are largely beyond the control of the service provider, they can designated as 100% cost-based This means that fuel costs would be cost-reimbursable Pricing would be based on a projection of these costs and be reviewed on an annual basis We refer to this as cost-based regulation

On the other hand, NCC may judge that material and supply costs are well within the control of the service provider As such they would contribute to a fixed revenue level that would be held constant in real terms over the three-year cost review cycle Reduction of such costs will contribute to increase profits for the service provider during the three-year period

It may be appropriate to regulate some cost categories under a combination of the two approaches In the example, export revenues (accounted for a negative costs) are designated as 25% incentive-based and 75% cost-based If export revenues are higher than projected during the three-year period, 25% of the increased revenue would go as profit to the LE and 75% would go to reduced cost that would flow through to retail tariffs

Variable and fixed costs are also defined by cost category Allocation to fixed and variable costs

The next section addresses the financial projections of the individual service providers

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FINANCIAL PROJECTIONS

Three-year financial projections are required for each of the service providers The key factors in these projections are the level of sales, investment requirements and method of financing, and projections for each operating cost category Table C-3 shows the projection for the generation/purchasing component of LE

Table C-3 Financial Projection for LE Generation

Year	1	2	3	Label	Description
Generation and purchases (GW h)	12031	12518	13133	$A1_t$	
(million Litas)					
Balance Sheet Items					
Investment Requirements	[illegible]	[illegible]	[illegible]	$A2_t$	
Fixed Assets	339	389	439	$A3_t$	$A3_t 1 \quad A2_{t-1}$
old investment	*339*	*339*	*339*	$A4_t$	
new investment	*0*	*50*	*100*	$A5_t$	$A5_{t-1} + A3_t 1$
Accumulated Depreciation	159	173	189	$A6_t$	$A6_{t-1} + B7_t 1$
old investment	*159*	*173*	*187*	$A7_t$	$A7_{t-1} + B8_t 1$
new investment	*0*	*0*	*2*	$A8_t$	$A8_t 1 + B9_t 1$
Construction in progress	*0*	*0*	*0*	$A9_t$	
Tariff basis	180	216	250	$A10_t$	$A10_t + A6_t$
old investment	*180*	*166*	*152*	$A11_t$	
new investment	*0*	*50*	*98*	$A12_t$	
Self investment ratio	40%	40%	40%	$A13_t$	
Long term Liabilities	141	166	191	$A14_t$	$A14_t 1 + (1 A12_t)*A2_t \quad A17_{t-1}$
Sources and Uses of Funds Items					
Long Term Debt Service	18	22	25	$A15_t$	function ($A14_t$)
Interest	*14*	*17*	*19*	$A16_t$	
Principal	*4*	*5*	*6*	$A17_t$	
Income Statement Items					
Fuel	114	115	116	$B1_t$	
Purchased Power	673	683	687	$B2_t$	from analysis of individual generators
Labor	12	12	13	$B3_t$	
Social security	4	4	4	$B4_t$	
Material and supplies	4	4	4	$B5_t$	
Repairs and maintenance	13	13	13	$B6_t$	
Depreciation	14	16	17	$B7_t$	function ($A6_t$)
old investment	*14*	*14*	*14*	$B8_t$	
new investment	*0*	*2*	*3*	$B9_t$	
Taxes (except income tax)	4	4	4	$B10_t$	
Other expenses	17	17	17	$B11_t$	
Interest on debt	11	11	11	$B12_t$	
Provision for doubtful accounts	0	0	0	$B13_t$	
Adjustments				$B14_t$	
Heat sales	0	0	0	$B15_t$	
Export sales	150	150	150	$B16_t$	
Subsidies	0	0	0	$B17_t$	
Total operating expense to be allocated to domestic generation	715	728	735	$B18_t$	sum ($B1_t$ $B7_t$ $B12_t$)

Other Projections

Generation- Ignalina NPP
Generation- Vilnius CHP
Generation- Kaunas CHP
Transmission (110 & 330 kV)
Distribution- Vilnius
Distribution- Kaunas
Distribution Klaipeda
Distribution- Siauliai
Distribution- Panevezys
Distribution- Alytus
Distribution- Utena
Generation- Lietuvos energia

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Table C-4 illustrates the estimation of a reasonable profit level for this entity In traditional US tariff setting, a reasonable profit level is determined by a regulated return on investment This approach depends on a high level of confidence in historical accounting and relatively low levels of inflation For these reasons, we do not think that this approach is currently appropriate for Lithuania We have selected two tests to determine the level of reasonable profit, both of which have to be met

Investment Requirements Test- The first test is to ensure an adequate level of self-investment and meet existing debt service The two sources of internal cash generation are depreciation and net profit These can be used to for new investment after paying principle on debt (interest is expensed in the financial projection), dividends and income taxes The calculation in Table C-4 shows the profit level required to meet the 40% self-investment target of the financial projections

Table C-4 Estimation of Reasonable Profit and Overall Revenue Requirements for LE Generation

Investment Requirements Test					
Year	1	2	3		Description
Internal cash generation requirements for investment and debt repayment	24	25	26	$C1_i$	$A12_i$*$A2_i$ + $A15_i$
Net profit requirement after dividend payment	10	10	9	$C2_i$	$C1_i$ - $B7_i$
Owner's dividend rate	15%	15%	15%	$C3_i$	
Profit before dividend payment	12	11	10	$C4_i$	$C2_i$ / (1-$C3_i$)
Profit tax rate	25%	25%	25%	$C5_i$	
Income taxes	4	4	3	$C6_i$	
Gross profit	16	15	14	$C7_i$	$C4_i$ / (1-$C5_i$)
Required revenue	731	743	749	$C8_i$	$B18_i$ + $C7_i$
Profitability Test					
Minimum return on new investment	10%	10%	10%	$C9_i$	
Net profit requirement after dividend payment	0	5	10	$C10_i$	$A12_i$*$C9_i$
Owner's dividend rate	15%	15%	15%	$C11_i$	
Profit before dividend payment	0	6	12	$C12_i$	$C10_i$ / (1-$C11_i$)
Profit tax rate	25%	25%	25%	$C13_i$	
Income taxes	0	2	4	$C14_i$	
Gross profit	0	8	15	$C15_i$	$C12_i$ / (1-$C13_i$)
Required revenue	715	736	751	$C16_i$	$B18_i$ + $C15_i$
Results					
Total Required Revenue	731	743	751	$C17_i$	max($C8_i$, $C16_i$)

Calculation of Profit Level and Total Revenue Requirements

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Profitability Test- As previously discussed, Defining the rate of return on existing assets is problematic due to questions of asset value However, new investments fully reflect market value and it is important that total net profits allow an adequate return for this new investment This is important whether or not strategic investors are being attracted or whether debt financing is being secured

In the example, the Investment Requirement Test is initially the determinant of the level of profit, the Profitability Test is key after the first year Other tests can be devised

The same tests are used for all service providers in the example It is possible to allow varying degrees of profit amongst service providers However, if this is done, there is a danger of unequal treatment in appearance if not in substance

Table C-5 shows the allocation of costs to those that are to be subject to cost-based regulation and those that are to contribute to the incentive revenue level based on the assumptions discussed previously and shown in Table C-2

Table C-5 Allocation of Costs to Cost-based and Incentive-base Categories

Year	1	2	3		Description
Costs Subject to Cost-based Regulation					
Fuel	114	115	116	$D1_i$	
Purchased Power	673	683	687	$D2_i$	
Adjustments					
Heat sales	0	0	0	$D13_i$	
Export revenues	113	113	113	$D14_i$	
Subsidies	0	0	0	$D15_i$	
Total	679	690	695	$D16_i$	sum ($D1_i$,$D15_i$)
Expected Payment (ct/kWh)	5 6	5.5	5.3	$D17_i$	$D16_i$ / $A1_i$
Costs Subject to Incentive Regulation					
Labor	12	12	13	$D20_i$	
Social security	4	4	4	$D21_i$	
Material and supplies	4	4	4	$D22_i$	
Repairs and maintenance	13	13	13	$D23_i$	
Depreciation	14	16	17	$D24_i$	
Taxes (except income tax)	0	0	0	$D25_i$	
Other expenses	17	17	17	$D26_i$	
Interest on debt	11	11	11	$D27_i$	
Provision for doubtful accounts	0	0	0	$D28_i$	
Gross profit	16	15	15	$D29_i$	
Adjustments					
Heat sales	0	0	0	$D30_i$	
Export revenues	38	38	38	$D31_i$	
Subsidies	0	0	0	$D32_i$	
Total	53	54	56	$D33_i$	sum ($D18_i$,$D32_i$)
Levelized Payment	54 0	54 0	54 0	$D34_i$	pmt (0 1 3 1)*npv (0 1 D33)

Allocation of Costs to Transfer Pricing Categories

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GENERATION PRICING

The financial projections provided by the generators provide estimates of future costs in real terms for the three-year period Those costs which are subject to cost-based regulation are reviewed annually and adjusted appropriately Those that are under incentive regulation are adjusted by only the inflation rate as measured by some agreed-upon index minus a productivity improvement factor set by the regulator

Table C-6 illustrates this process for the first year for the generation/purchasing component of LE and for Ignalina NPP The same calculations are made for all generators

Four columns are shown The first represents projections made at the beginning of the year The second shows actual values at the end of the year The third column shows the required adjustments for the next year to reflect discrepancies between projected and actual values and the fourth shows how the adjustments are applied at the beginning of the second year The first column would be fill out at the beginning of the three year review period for purposes of generation price and retail tariff calculation Columns 2 through 3 would be filled out at the end of the first year Column 4 would be used to determine generation price and retail tariff calculation at the beginning of the second year

Incentive regulation
Costs estimated based on projected inflation Adjustments made based on difference between projected and actual inflation

Cost-based regulation
Adjustments made based on differences between projected and actual

Yearly adjustments
Charged interest at short-term interest rate

Table C-6 Generation Payments and Cost Adjustments

	Labels	1	Description	2	Description	3	Description	4	Description
		estimated		actual		required adjustment for next year		estimated	
Year				1					
Inflation	Aa	20%		15%				15%	
Short-term interest rate	Ab					20%			
(millions Litas)									
Lietuvos energia									
Incentive-based expenses before inflation	Ba	54.0						61.1	Bc3
Productivity improvement rate	Bb	5%						5%	
Incentive-based expenses after inflation	Bc	63.8	Ba1* (1+Aa1-Bb1)	61.1	Ba1* (1+Aa2-Bb1)			69.0	Ba4* (1+Aa4-Bb4)
Cost-based expenses									
Purchased power	Bd	806.5	Cg1+Dg1+Eg1	857.2	Cg2+Dg2+Eg2			953.6	Cg4+Dg4+Eg4
Other	Be	6.2		10.0				8.4	
Total	Bf	812.7	Bd1 + Be1	867.2	Bd2 + Be2			962.0	Bd4 + Be4
Cost adjustment from previous year	Bg	0.0		0.0	Bg1			62.2	
Revenue adjustment from previous year	Bh	0.0		0.0	Bh1			5.8	
Total	Bi	876.4	sum(Bc1,Bf1:Bh1)	928.2	sum(Bc2,Bf2:Bh2)	62.2	(Bi2-Bi1)*(1+Ab3)	1087.4	sum(Bc4,Bf4:Bh4)
Ignalina NPP									
Incentive-based expenses before inflation	Ca	0.0						0.0	
Productivity improvement rate	Cb	5%						5%	
Incentive-based expenses after inflation	Cc	0.0	Ca1 (1+Aa1-Cb1)	0.0	Ca1* (1+Aa2-Cb1)			0.0	Ca4* (1+Aa4-Cb4)
Cost-based expenses	Cd	752.3		800.0				837.4	
Cost adjustment from previous year	Ce	0.0		0.0	Ce1			57.3	
Revenue adjustment from previous year	Cf	0.0		0.0	Cf1			3.8	
Total	Cg	752.3	sum(Cc1:Cf1)	800.0	sum(Cc2:Cf2)	57.3	(Cg2-Cg1)*(1+Ab3)	890.9	sum(Cc4:Cf4)

Generation payments and cost adjustments

The table refers to cost adjustments and revenue adjustments There are two types of cost adjustments The first is associated with costs under incentive pricing Adjustments associated with these costs are

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calculated to reflect differences in inflation projected at the beginning of the year and what was actually experiences Adjustments to costs under cost-based regulation are based on differences between projected and actual values

The incentive methodology used in this example is intended to provide a level source of revenue to cover costs subject to this type of regulation Pricing is based on projected sales If sales differ from projected values the amount of revenue available to cover costs under incentive regulation will also vary Revenue adjustments are made at the end of the year to correct for this

Table C-6 shows the calculation of generation price by independent generators, the contribution of LE generation/purchasing to retail tariffs, and the required revenue adjustments based on differences between projected and actual sales

LE Generation costs include purchases from other generators

Therefore, its costs represent full impact of generation on retail tariffs

Modifications to methododology would be required if individual generators were allowed to contract directly with distributors

Differential impact on retail tariffs based on losses by voltage level (Losses)

Table C-7 Generation Revenue Adjustments and Contribution to Retail Tariffs

	Labels	1	Description	2	Description	3	Description	4	Description
		estimated		actual		required adjustment for next year		estimated	
Year				1					
Short-terminterest rate	Fa					20%			
Lietuvos energia									
Production & purchases (GWh)	Ga	12081						12518	
Retail sales (GWh)									
110 kV system	Gc	1132		1125				1200	
6 35 kV system	Gd	1415		1350				1500	
4 kV system	Ge	4752		4850				5000	
Total	Gf	7299		7325				7700	
Ratio of price to 110 kV level			based on average losses						based on average losses
> 4 kV and < 110 kV system	Gh	1.06						1.06	
4 kV system	Gi	1.28						1.28	
Total cost to be covered (millions Litas)	Gj	876.4	Bl1					1087.4	Bl4
% of incentive regulated costs fixed									
Average tariff component to cover generation (ct/kWh)	Gk								
110 kV system	Gl	10.1	Gj1/(Gc1+Gh1*Gd1+Gl1*Ge1)*100					11.8	Gj4/(Gc4+Gh4*Gd4+Gl4+Ge4)*100
> 4 kV and < 110 kV system	Gm	10.7	Gl1*Gh1					12.6	Gl4*Gh4
4 kV system	Gn	12.9	Gl1*Gi1					15.1	Gl4*Gi4
Retail revenues associated with generation (million Litas)	Go	876.4	(Gl1*Gc1+Gm1*Gd1+Gn1*Ge1)/100	881.4	(Gl1*Gc2+Gm1*Gd2+Gn1*Ge2)/100			1087.4	(Gl4*Gc4+Gm1*Gd4+Gn4*Ge4)/100
% of incentive regulated costs variable	Gp	31%				5.8	(Gp1-Gp2)*(1-Bc1/Bl1*Gp1)*(1+Ab3)	31%	
Ignalina NPP									
Production & purchases (GWh)	Ia	10226		10269				10641	
Total cost to be covered (millions Litas)	Ib	752.3	Cg1					860.9	Cg4
Average cost (ct/kWh)	Ic	7.4	Cg1 / Ia1					8.4	Cg4 / Ia4
Revenue (million Litas)	Id	752.3	Ia1 * Ic1	755.4	Ia1 Ic2			860.9	Ia4 * Ic4
% of incentive regulated costs variable	Ie	100%				3.8	(Ie1-Ie2)*(1 Cc1/Cg1 Ie1)*(1+Ab3)	100%	

Generation revenue adjustments contribution to retail tariff

Revenue adjustments are made on Line Gp for Lietuvos energia and Ie for Ignalina NPP The fraction of the incentive-regulated costs that are variable is based on the fixed and variable allocations discussed earlier (Allocation to fixed and variable costs)

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In the case of costs subject to cost-based regulation, some higher (or lower) costs may be due to higher (or lower) demand Cost adjustments made previously to reflect these higher (or lower) costs are offset by higher (or lower) revenues If the projected per unit cost were to be achieved, cost adjustments under cost-based regulation would be completely offset by revenue adjustments

On the other hand, under a revenue cap, the only cost adjustment to the amount of revenue intended to cover costs subject to incentive regulation is for differences in projected and actual inflation If demand is higher (or lower) the cost adjustment is not affected However, to the extent that some variable costs (i e , costs varying with demand) may be subject to incentive regulation, higher (or lower) demand should affect the amount of revenue allowed to cover these costs For example, if 20% of the incentive-regulated costs were variable, an increase in demand over projected values of 10% should result in a 2% increase in revenues to cover these costs The increased demand will result in a 10% increase so that the necessary per unit revenue adjustment should be 8% (i e , 10%-2%)

The following equations show the per unit adjustments made under each type of regulation assuming no discrepancies between projected and actual inflation and no differences in costs other than those that are demand-related

Fraction change in difference in projected and actual demand and resulting revenue change						d
Type of regulation	Relative size	Fraction variable	Fraction change in cost	Fraction cost adjustment	Necessary per unit revenue adjustment	Weighted revenue adjustment
Cost-based	A1	B1	B1*d	B1*d	d	A1/(A1+A2)*d
Incentive	A2	B2	B2*d	0	d - B2*d	A2/(A1+A2)*(1-B2)* d
						d*(1-A2/(A1+A2)*B2)

In the case of costs under cost-based regulation variable costs will change according the to amount of demand change and will be reflected directly in the annual cost adjustment Revenues will vary according to this demand change and will be adjusted accordingly The total adjustment is the fraction change in demand times the fraction of costs that are fixed (i e , one minus the fraction of the costs that are variable)

Incentive-regulated costs receive no cost adjustment in the case of projected versus actual demand differences However the demand per unit revenue adjustment is made such that the total adjustment in the fraction change in demand times the fraction of costs that are fixed as in the case of costs under cost-based regulation

4d

The derivation for the weighted average revenue adjustment, used in the spreadsheet is given

The selection of "revenue cap" over "price cap" for incentive-regulated costs was based on the judgement that only a small part of these costs were demand-related (i e , less than 25%) If a larger portion of the costs are demand-related than assumed in the example, it may be appropriate to use a "price cap" approach

The cost and revenue adjustments for transmission and distribution are analogous to those for generation

TRANSMISSION PRICING

The generation pricing approach presented above may become less necessary when the Lithuanian power is less dominated by a single supplier and competitive elements are introduced However, the transmission system will remain a natural monopoly and non-discriminatory pricing will be a critical to the introduction of competition

In this methodology, financial projections for the transmission system are made analogously to those of the various generators (Transmission (110 & 330 kV)) The calculation of transmission payments and annual adjustments and their impact on retail tariffs is shown in Tables C-7 and C-8

Why are costs subject to cost-based regulation negative in example?

1 Transit sales and transmission share of export revenues are treated as negative costs

2 75% of these revenues subject to cost-based regulation

3 Other costs subject to cost-based regulation (primarily taxes) are small

Table B 8 Transmission Payments and Cost Adjustments

	Labels	1	Description	2	Description	3	Description	4	Description
		estimated		actual		required adjustment for next year		estimated	
Year				1					
Inflation	Aa	20%		15%				15%	
Short-terminterest rate	Ab					20%			
(millions Litas)									
Lietuvos energia									
Incentive-based expenses before inflation	Ba	248.0						280.3	Bc3
Productivity improvement rate	Bb	[illegible]						[illegible]	
Incentive-based expenses after inflation	Bc	292.7	Ba1* (1+Aa1-Bb1)	280.3	Ba1 (1+Aa2-Bb1)			316.7	Ba4* (1+Aa4-Bb4)
Cost-based expenses									
Purchased power	Bd	0.0	1+1+1	0.0	2+2+2			0.0	4+4+4
Other	Be	16.1		10.0				17.6	
Total	Bf	16.1	Bd1 + Be1	10.0	Bd2 + Be2			17.6	Bd4 + Be4
Cost adjustment from previous year	Bg	0.0		0.0	Bg1			7.5	
Revenue adjustment from previous year	Bh	0.0		0.0	Bh1			1.5	
Total	Bi	276.6	sum(Bc1,Bf1:Bh1)	270.3	sum(Bc2,Bf2:Bh2)	7.5	(Bi2-Bi1)*(1+Ab3)	290.1	sum(Bc4,Bf4:Bh4)

Transmission payments and cost adjustments

Differential impact on retail tariffs based on losses by voltage level (Losses)

Table B 9 Transmission Revenue Adjustments and Contribution to Retail Tariffs

	Labels	1	Description	2	Description	3	Description	4	Description
		estimated		actual		required adjustment for next year		estimated	
Year		1							
Short-terminterest rate	Fa					20%			
Lietuvos energija									
Transmission (not including transit, GWh)	Ga	8948						9406	
Retail sales (GWh)									
110 kVsystem	Gc	1132		1125				1200	
6 35 kVsystem	Gd	1415		1350				1500	
4 kVsystem	Ge	4752		4850				5000	
Total	Gf	7299		7325				7700	
Ratio of price to 110 kV level			based on average losses						based on average losses
>.4 kV and < 110 kVsystem	Gh	1 06						1.06	
4 kVsystem	Gi	1.28						1.28	
Total cost to be covered (millions Litas)	Gj	276.6	Bi1	270.3				290.1	Bi4
Average tariff component to cover generation (ct/kWh)	Gk								
110 kVsystem	Gl	3.2	Gj1/(Gc1+Gh1*Gi1+ Gf1*Ge1)*100					3.2	Gj4/(Gc4+Gh4*Gi4+ Gf4*Ge4)*100
6 35 kVsystem	Gm	3.4	Gl1*Gh1					3.4	Gl4*Gh4
4 kVsystem	Gn	4.1	Gl1*Gi1					4.0	Gl4*Gi4
Retail revenues associated with transmission (million Litas)	Go	276.6	(Gl1*Gc1+Gm1*Gd1 +Gn1*Ge1)/100	278.1	(Gl1*Gc2+Gm1 Gd2 +Gn1*Ge2)/100			290.1	(Gl4*Gc4+Gm4*Gd4+ Gn4*Ge4)/100

Transmission revenue adjustment and contribution to retail tariff

DISTRIBUTION PRICING

Table C-10 shows the first-year payments and cost adjustments for the Vilnius and Kaunas distribution subsidiaries of LE The adjustments to reflect differences in projected and actual sales and the impact of distribution on retail tariff are shown in Table C-11 Analogous calculations are made for other distribution subsidiaries

Table C-10 Distribution Payments and Cost Adjustments

	Labels	1	Description	2	Description	3	Description	4	Description
		estimated		actual		required adjustment for next year		estimated	
Year		1							
Inflation	Aa	20%		15%				15%	
Short-terminterest rate	Ab					20%			
(millions Litas)									
Vilnius									
Incentive-based expenses before inflation	Ba	106.7						120.5	
Productivity improvement rate	Bb	2%						2%	
Incentive-based expenses after inflation	Bc	125.9	Ba1 (1+Aa1-Bb1)	120.5	Ba1 (1+Aa2-Bb1)			136.2	Ba4* (1+Aa4-Bb4)
Cost-based expenses	Bd	5.5		5.0				6.1	
Cost adjustment from previous year	Be	0.0		0.0	Be1			7.0	
Revenue adjustment from previous year	Bf	0.0		0.0	Bf1			1.5	
Total	Bg	131.4	sum(Bc1:Bf1)	125.5	sum(Bc2:Bf2)	7.0	(Bg2-Bg1)*(1+Ab3)	133.9	sum(Bc4:Bf4)
Kaunas									
Incentive-based expenses before inflation	Ca	112.8						127.4	
Productivity improvement rate	Cb	2%						2%	
Incentive-based expenses after inflation	Cc	133.1	Ca1 (1+Aa1-Cb1)	127.4	Ca1 (1+Aa2-Cb1)			144.0	Ca4* (1+Aa4-Cb4)
Cost-based expenses	Cd	5.9		5.0				6.5	
Cost adjustment from previous year	Ce	0.0		0.0	Ce1			7.8	
Revenue adjustment from previous year	Cf	0.0		0.0	Cf1			1.0	
Total	Cg	139.0	sum(Cc1:Cf1)	132.4	sum(Cc2:Cf2)	7.8	(Cg2-Cg1)*(1+Ab3)	141.7	sum(Cc4:Cf4)

Distribution payments and cost adjustments

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Differenctial impact of distribution costs on tariffs by voltage level based on assumed ratios (Relationship of retail tariffs to 110 kV tariff)

Ratios can be based on marginal cost studies, cost accounting by voltage level, and/or comparisons with other countries

Table C-11 Distribution Revenue Adjustments and Contribution to Retail Tariffs

		1	Description	2	Description	3	Description	4	Description
		estimated		actual		required adjustment for next year		estimated	
Year		1							
Short-term interest rate	Ia					20%			
Vilnius									
Purchases (GWh)	Ja	1888		1907				1990	
Retail sales (GWh)									
110 kV system	Jc	172		171				183	
6 35 kV system	Jd	214		204				227	
4 kV system	Je	1165		1189				1226	
Total	Jf	1551		1564				1635	
Ratio of price to 110 kV level			based on set ratio						based on set ratio
> 4 kV and < 110 kV system	Jh	1.20						1.20	
4 kV system	Ji	1.70						1.70	
Total cost to be covered (millions Litas)	Jj	131.4	Bg1					133.9	Bg4
Average tariff component to cover generation (ct/kWh)	Jk								
110 kV system	Jl	5.5	Jj1/(Jc1+Jh1*Jd1+Ji1 Je1)*100					5.3	Jj4/(Jc4+Jh4 Jd4+Ji4* Je4)*100
> 4 kV and < 110 kV system	Jm	6.5	Jl1*Jh1					6.3	Jl4 Jh4
4 kV system	Jn	9.3	Jl1 Ji1					9.0	Jl4 Ji4
Retail revenues associated with distribution (million Litas)	Jo	131.4	(Jl1 Jc1+Jm1 Jd1+Jn1 *Je1)/100	132.9	(Jl1*Jc2+Jm1 Jd2+Jn1 Je2)/100			133.9	(Jl4*Jc4+Jm4 Jd4+Jn 4*Je4)/100
% of incentive regulated costs variable	Jp	21%				1.5	(Jp1 Jp2)*(1 Bc1/Bg1 Jp1)*(1+Ab3)	20%	

Distribution revenue adjustment and contribution to retail tariff

TRANSFER PAYMENTS

During the cost review period, prices for generation and transmission services and retail tariffs are set at the beginning of the year based on projections Adjustments are made at the end of the year for use in price and tariff setting for the next year Table C-11 summarizes this process for payments to generators and the transmission entity for the three year period The table is based on assumed actual values for inflation, costs subject to cost-based regulation and sales The "adjustments from previous year" shown for each entity is the sum of all cost and revenue adjustments Their calculation is shown in Tables C-6 and C-7 for generation and Tables C-8 and C-9 for transmission

Generation and transmission prices and retail tariffs based on annual projections and corrections from previous years

Revenues based on prices and actual sales

Table C-12 Payments for Generation and Transmission

Year	1	2	3		1	2	3
Payments for Generation (millions Litas)							
Lietuvos energia				Vilnius CHP			
Planned generation + purchases exports (GWh)	8948	9436	10051	Planned generation (GWh)	241	250	263
Actual generation + purchases exports (GWh)	8998	9382	9755	Actual generation (GWh)	242	249	257
Contributions to revenues (millions Litas)				Contributions to revenues (millions Litas)			
Costs under incentives	61	67	73	Costs under incentives	21	23	25
Costs under cost-based regulation	867	1054	1188	Costs under cost-based regulation	25	25	25
Adjustments from previous year	0	56	106	Adjustments from previous year	0	5	3
Revenues in addition to costs	-47	-96	-135	Revenues in addition to costs	-4	-2	-2
Total	881	1081	1233	Total	42	50	50
Average price including purchases (ct/kWh)	9.8	11.5	12.6	Average price (ct/kWh)	17.4	20.2	19.6
Ignalina NPP				Kaunas CHP			
Planned generation (GWh)	10226	10641	11163	Planned generation (GWh)	48	48	50
Actual generation (GWh)	10269	10595	10912	Actual generation (GWh)	48	50	51
Contributions to revenues (millions Litas)				Contributions to revenues (millions Litas)			
Costs under incentives	0	0	0	Costs under incentives	8	9	10
Costs under cost-based regulation	800	925	1000	Costs under cost-based regulation	3	5	5
Adjustments from previous year	0	54	108	Adjustments from previous year	0	1	1
Revenues in addition to costs	-45	-91	-117	Revenues in addition to costs	1	1	1
Total	755	887	991	Total	12	12	15
Average price (ct/kWh)	7.4	8.4	9.1	Average price (ct/kWh)	25.8	24.7	29.3
Payments for Transmission (millions Litas)				Note: Revenue for exports considered a negative cost for Lietuvos energia domestic generation and transmission Revenue from transit sales considered a negative cost for Lietuvos energia domestic transmission.			
Lietuvos energia							
Planned domestic transmission service (GWh)	8948	9436	10051				
Actual domestic transmission service (GWh)	8998	9382	9755				
Associated losses (GWh)	241	252	262				
Contributions to revenues (millions Litas)							
Costs under incentives	280	308	336				
Costs under cost-based regulation	10	15	25				
Adjustments from previous year	0	-9	5				
Revenues in addition to costs	8	4	-6				
Total	278	288	300				
Average price at generation level (ct/kWh)	3.1	3.1	3.1				
Average price at distribution level (ct/kWh)	3.2	3.2	3.2				
Average price to distributors for generation and transmission (ct/kWh)	13.2	15.0	16.1				

Generation and Transmission Payments

Table C-13 shows the payments for show the payments for generation and transmission services made by each distribution subsidiary, their charges for distribution services and final average tariffs

Table C- 13 Total Payment Summary by Distribution Subsidiary (millions Litas)

Year	1	2	3		1	2	3
Payments at Distribution Level (millions Litas)							
Lietuvos energia							
Vilnius				**Panevezys**			
Projected retail sales (GWh)	1551	1635	1746	Projected retail sales (GWh)	902	952	1009
Actual retail sales (GWh)	1564	1648	1712	Actual retail sales (GWh)	901	922	959
Revenue				Revenue			
110 kV system	32	40	44	110 kV system	32	40	45
6 35 kV system	42	34	37	6 35 kV system	43	35	39
4 kV system	311	366	400	4 kV system	139	164	180
Total	385	439	481	Total	214	239	263
Purchases (GWh)	1907	2018	2097	Purchases (GWh)	1059	1090	1134
Payments for generation	192	239	272	Payments for generation	107	129	147
Payments for transmission	61	64	66	Payments for transmission	34	34	36
Total G&T payments	253	303	339	Total G&T payments	140	164	183
Payment for distribution service	133	136	143	Payment for distribution service	74	76	80
Average distribution price (ct/kWh)	8.5	8.3	8.3	Average distribution price (ct/kWh)	8.2	8.2	8.3
Average retail price (ct/kWh)	24 6	26 7	28 1	Average retail price (ct/kWh)	23 8	26 0	27 4
Kaunas				**Alytus**			
Projected retail sales (GWh)	1653	1744	1855	Projected retail sales (GWh)	553	584	619
Actual retail sales (GWh)	1659	1722	1791	Actual retail sales (GWh)	553	566	589
Revenue				Revenue			
110 kV system	48	59	66	110 kV system	20	25	27
6 35 kV system	63	50	56	6 35 kV system	26	21	23
4 kV system	293	343	377	4 kV system	86	103	112
Total	403	453	498	Total	132	150	163
Purchases (GWh)	1985	2071	2154	Purchases (GWh)	651	670	698
Payments for generation	200	245	280	Payments for generation	65	79	91
Payments for transmission	63	65	68	Payments for transmission	21	21	22
Total G&T payments	263	311	348	Total G&T payments	86	101	113
Payment for distribution service	140	142	151	Payment for distribution service	46	49	50
Average distribution price (ct/kWh)	8 4	8.2	8 4	Average distribution price (ct/kWh)	8.3	8 6	8.5
A erage retail price (ct/kWh)	24.3	26.3	27.8	Average retail price (ct/kWh)	23 9	26 4	27 6
Klaipeda				**Utena**			
Retail sales (GWh)	1009	1064	1136	Projected retail sales (GWh)	345	364	388
Actual retail sales (GWh)	1017	1069	1112	Actual retail sales (GWh)	348	364	378
Revenue				Revenue			
110 kV system	22	28	30	110 kV system	7	9	10
6 35 kV system	29	23	26	6 35 kV system	11	9	10
4 kV system	198	236	255	4 kV system	67	80	85
Total	249	287	311	Total	85	98	105
Purchases (GWh)	1237	1306	1357	Purchases (GWh)	422	444	461
Payments for generation	124	155	176	Payments for generation	42	53	60
Payments for transmission	39	41	43	Payments for transmission	13	14	15
Total G&T payments	164	196	219	Total G&T payments	56	67	74
Payment for distribution service	85	91	92	Payment for distribution service	29	32	30
Average distribution price (ct/kWh)	8 4	8.5	8.2	Average distribution price (ct/kWh)	8.3	8 8	8.0
Average retail price (ct/kWh)	24.5	26.8	27 9	Average retail price (ct/kWh)	24 4	27 1	27 7
Siauliai				**Summary all Distribution**			
Projected retail sales (GWh)	1286	1358	1438	Projected retail sales (GWh)	7299	7700	8190
Actual retail sales (GWh)	1283	1305	1358	Actual retail sales (GWh)	7325	7595	7900
Revenue				Re enue			
110 kV system	51	64	71	110 kV system	212	266	294
6 35 kV system	68	54	60	6 35 kV system	281	226	251
4 kV system	186	218	241	4 kV system	1280	1510	1649
Total	305	336	373	Total	1774	2002	2194
Purchases (GWh)	1495	1530	1592	Purchases (GWh)	8757	9130	9494
Payments for generation	151	181	207	Payments for generation	881	1081	1233
Payments for transmission	47	48	50	Payments for transmission	278	288	300
Total G&T payments	198	229	257	Total G&T payments	1159	1370	1533
Payment for distribution service	107	107	116	Payment for distribution service	614	633	661
Average distribution price (ct/kWh)	8.3	8.2	8.5	Average distribution price (ct/kWh)	8 4	8.3	8 4
Average retail price (ct/kWh)	23 8	25.8	27.5	Average reta l price (ct/kWh)	24.2	26 4	27.8

Distribution Payments

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RETAIL TARIFFS

Table C-14 summarizes the resulting retail tariffs by voltage level and the contribution of the charges of various service providers to those tariffs The contribution of the various components are calculated in Tables C-7, C-9 and C-11 for generation, transmission and distribution, respectively

Table C- 14 Retail Tariff Summary (ct/kWh)

	Contribution of Components to Final Retail Tariffs			Retail Tariffs		
Year 1						
	110 kV	*4 - 35 kV*	*4 kV*	*110 kV*	*4 - 35 kV*	*4 kV*
Generation	10 1	10 7	12 9			
Transmission	3 2	3 4	4 1			
Distribution						
Vilnius	5 5	6 5	9 3	18 7	20 6	26 2
Kaunas	5 6	6 7	9 5	18 9	20 8	26 5
Klaipeda	5 4	6 5	9 2	18 6	20 6	26 1
Siauliai	5 8	7 0	9 9	19 1	21 1	26 9
Panevezys	5 7	6 8	9 6	18 9	20 9	26 5
Alytus	5 7	6 9	9 7	19 0	20 9	26 6
Utena	5 4	6 5	9 2	18 6	20 5	26 1
Year 2						
	110 kV	4 35 kV	4 kV	110 kV	4 - 35 kV	4 kV
Generation	11 8	12 6	15 1			
Transmission	3 2	3 4	4 0			
Distribution						
Vilnius	5 3	6 3	9 0	20 3	22 3	28 1
Kaunas	5 4	6 5	9 2	20 4	22 5	28 4
Klaipeda	5 4	6 5	9 2	20 4	22 5	28 4
Siauliai	5 7	6 8	9 7	20 7	22 8	28 8
Panevezys	5 6	6 7	9 5	20 6	22 7	28 7
Alytus	5 9	7 0	10 0	20 9	23 0	29 2
Utena	5 6	6 8	9 6	20 6	22 7	28 7
Year 3						
	110 kV	4 - 35 kV	4 kV	110 kV	4 35 kV	4 kV
Generation	13 0	13 8	16 6			
Transmission	3 2	3 4	4 0			
Distribution						
Vilnius	5 3	6 4	9 0	21 5	23 5	29 7
Kaunas	5 5	6 7	9 4	21 7	23 8	30 1
Klaipeda	5 3	6 3	9 0	21 4	23 5	29 6
Siauliai	5 9	7 1	10 1	22 1	24 3	30 7
Panevezys	5 7	6 8	9 6	21 8	24 0	30 3
Alytus	5 8	7 0	9 8	21 9	24 1	30 5
Utena	5 1	6 2	8 7	21 3	23 3	29 4

Example only- These results should not be used to determine pricing or measure performance of individual generators or distributors

Tariff Summary

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