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National Association of Regulatory Utility Commissioners

ERRA
ENERGY REGULATORS REGIONAL ASSOCIATION

Cost Allocation & Methods for Distribution and Supply

ERRA TARIFF/PRICING COMMITTEE

2005

Introduction

Dear Ladies and Gentleman:

The Tariff/Pricing Committee was established in December 1998 as a part of the Energy Regulators Regional Association (established by NARUC in cooperation with US Agency for International Development). In December 2000, the Committee was officially approved as one of the two ERRA standing committees.

Currently the Tariff/Pricing Committee includes 21 full members and 3 associate members. In 2004 the State Energy Regulatory Commission of Bosnia and Herzegovina and the Energy Regulatory Commission of Macedonia joined Tariff/Pricing Committee. In 2005 the Energy Regulatory Office of Kosovo was adopted as an associate member of ERRA.

Each year the Committee members select topics subject of development taking into account wishes and priority objectives of the regulatory organizations from member countries. Regardless of different stages of the reforms in the energy sector in different countries we look for a balance and make attempts to satisfy the needs of new members as well as those of the countries with longer experience in the regulation.

It is my pleasure to present you the issue paper developed by the Tariff/Pricing Committee in 2005 – "Cost Allocation & Methods for Distribution and Supply" with the leading role of Ms. Aistija Zubaviciute - Vice-Chair of the ERRA Tariff/Pricing Committee, National Control Commission for Prices and Energy, Lithuania, Mr. Çetin Kayabaş, Energy Market Regulatory Authority (EMRA), Turkey, and Ms. Denise Parrish, Wyoming Public Service Commission, USA.

I would like to express my sincere appreciation to all Committee members for making this paper available to all ERRA members and to the public. I also want to thank US Agency for International Development, NARUC and ERRA for their continuous technical support, comprehensive assistance and valuable suggestions.

I strongly believe that our fruitful cooperation will continue and look forward to Committee's future growth.

Sincerely:

Svetla Todorova

Chair of the Tariff/Pricing Committee

Commissioner, State Energy and Water Regulatory Commission of Bulgaria

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USAID FROM THE AMERICAN PEOPLE Publication and dissemination of the documents pertaining to the 5th Annual Meeting of Energy Regulators Regional Association (ERRA) was made possible through support provided by the Energy and Infrastructure Division of the Bureau of Europe and Eurasia under the terms of its Cooperative Agreement with the National Association of Regulatory Utility Commissioners, No. EE-N-00-99-00001-00.

The opinions expressed herein are those of the authors and do not necessarily reflect the views of the U.S. Agency for International Development.

Cost Allocation and Methods for Distribution and Supply

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1. Introduction

Cost allocation is a basic step towards the setting of prices. The objective, transparent and non-discriminatory tariff structure depends on how we define the precise costs, what criteria we use for their allocation, price differentiation and how the entire pricing arrangement is harmonized. Consequently it reflects the right signals to the consumers and makes the electricity system reliable and more efficient.

2. Purpose of this paper

There are different models or structures of the electricity market in the different countries. Some of them still have the vertically integrated power companies, while some have already unbundled their energy company according to the technological stages: generation, transmission, distribution and supply. Supply activity usually is separated into two types: an independent supplier and a public (last resort) supplier. Independent suppliers participate in the market and sell electricity on the basis of negotiated prices, while the public suppliers are obliged to sell electricity to all or some (depending on the rules in the country) customers, based on regulated prices. This reorganization of the electricity sector is a precondition of a competitive market.

Electricity pricing should be modeled accordingly. Competition is possible where there is the potential for more market participants, such as in the generation market, but not in the transmission and distribution market, where it is irrational to build parallel transmission or distribution networks. By this logic, the generation and supply activities should be free from price regulation, whereas the transmission and distribution services should be regulated;, The latter services are called as natural monopolies. ***This Issue Paper will mainly be focused on cost allocations – for the unbundled market structure.***

3. Summary of main principles

When allocating costs for the still regulated, vertically integrated company (or the ***monopoly model***), we first- define the total revenue requirement of all electricity technological stages: generation, transmission (high voltage), distribution (medium and low voltage) and supply. A common amount of profit is added for all these activities. As a rule, the electricity tariff structure is differentiated according to the voltage levels, using the proportion of fixed assets or consumption,

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depending on how many voltage levels we have made or the number of electricity supply points to users that are reasonable. Summarizing these costs, we get the needed revenue requirement for each of the voltage levels. Dividing the mentioned costs by the electricity volume for each corresponding voltage levels or consumption point, we have the average prices.

The next step is to make such average prices reflect the cost causality in order to send the right signals to the consumers. As we will see in Sections 8 and 9 below, there are different ways to structure the whole tariff. We could call this an art, rather than a science.

For a ***competitive market***, after designing the unbundled market structure and defining market participants' relationships, we need to calculate the transportation and public supply prices separately and differentiate them, since generation and independent supply are not normally regulated activities, as mentioned above. Of course, there are possible exceptions. For instance, generators and suppliers, which have a major part of the electricity sale market, could be regulated in order to avoid their dominance and abuse in the market.

When there is a reorganized electricity market, the transmission and distribution companies are unbundled, and therefore, we do not face the problem of how to allocate the transportation costs. (In the case of the monopoly model, we allocated such costs by the fixed assets or consumption criteria.) Once we have the transmission and distribution service prices, we could differentiate them according to the two-part tariff (energy and demand components). This reflects the cost causality and is used in most countries. These components could also be differentiated by the load factor, maximum capacity, volume of consumption and other criteria.

Public supply or last resort supplier cost could be separated from the distribution costs on the direct & non-direct cost attribution approach, which is also used in many countries, as we will see it from Section 6. If they are separate companies, it is even better, as there is more transparency in the distribution and supply activities.

Supply price could be differentiated by the abonent tariff per customer or meter, because these costs are fixed and do not depend on the consumption variations.

4. Cost Allocation guidelines and price objectives

The following guidelines may be followed when allocating costs:

- *Cost causality* - revenues, costs, assets and liabilities should be attributed in accordance with the activities which cause the revenues to be earned or the cost to be incurred;
- *Objectivity* - recharging of costs should be performed on an objective basis and should not unduly benefit the regulated company or other;
- *Consistency* - costs should be consistent from year to year; and
- *Transparency* - attribution, allocation and inter-business of all elements, should be distinguishable from each other.

In allocating cost, we should take into account that the regulated electricity prices are the substitute of market prices. Thus, the following objectives should be applied to the electricity prices:

1. *Least costs* – the prices shall serve as an incentive to the power companies to render the least cost services to their customers;

2. *Cost reflection* – the prices shall reasonably and correctly reflect the costs of respective activities in the energy sector incurred in rendering services to customers, as well as the cost entry

based on the customers' needs, e.g. related to the construction of new generation sources and the growth of electricity consumption;

3. *Cost coverage* – the prices shall be adequate to secure sufficient revenues for power companies;

4. *Simplicity* – the price structure shall be understandable to customers, enabling them to calculate their bills and to predict factors, which may cause alterations in prices;

5. *Stability* – avoiding high and frequent price fluctuations;

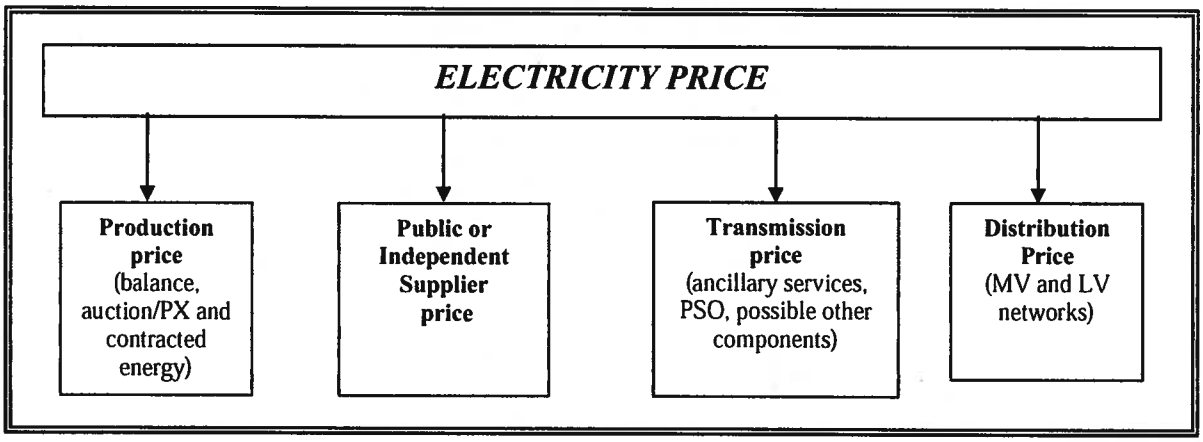
6. *Flexibility* – the price structure shall be sufficiently flexible to reflect changes in costs, in spite of the fact that this may raise a conflict with the desire for stability; and

7. *Equality* – the prices shall discriminate neither against the customers nor their groups, and shall not be based on cross-subsidies.

5. Cost types

Knowing the electricity price objectives, we try to treat the costs accordingly. As mentioned above, we first define the costs by technological stage, in order to allow for transparent pricing and market preconditions. In doing so, we create a price for each major activity instead of one total electricity price (1 pic.).

1 pic. Electricity price after reorganization of Energy Company



In the regulatory practice we could find such main cost types in the 1 table.

1 table. Cost types

No.	Name of costs	Brief description
1.	Generation	Cost, related to the electricity generated in the power plants
1.1.	Balance energy	Cost, related to the deviations from the planned energy supply in the schedule
1.2.	Auction or PX energy	Cost, related to the electricity sold in the Auction or Power Exchange (PX)
1.3.	Contracted	Cost, related to the electricity purchased by the mutual agreements
4.	Public Supply	Cost, related to the services to customers
5.	Independent Supply	Cost, related to the supply to customers who participate in the market
6.	Transmission	Cost, related to the electricity transportation over the HV network
6.1.	Ancillary services	Cost, related to the reliability and balance of the energy system

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6.2.	Public Service Obligations (PSO)	Cost, related to services which are pursuant to the public interest and set by the Government or other state institution
7.	Distribution	Cost, related to the electricity transportation over the MV or LV network
7.1.	MV network	Part of the distribution network with medium voltage
7.2.	LV network	Part of the distribution network with low voltage
13.	Fixed	Cost, which does not vary depending on the electricity volume and are mostly stable all the time
14.	Variable	Cost, which increases with increases in the electricity consumption and in opposite, i.e. depend on the electricity volume
15.	Average	These costs show the average cost based on an assumed amount of volume
16.	Marginal	These costs show the change of average cost, if the consumption increases/decreases by one unit. They are short run and long run.
17.	Power	Cost, related with the users' maximum capacity (usually they are a part of fixed cost)
18.	Energy	Cost, related with the consumed electricity (usually they are variable cost)
19.	Abonent	Cost, related with the users' service: metering, billing, etc. (usually they are a part of fixed cost)

Based on a desire to create an electricity market, vertically integrated energy companies are unbundled. The rest of the cost allocation depends on the structure of the market, the provisions of the Laws, rules and the creativity of the person making the tariff structure. When we have the unbundled Energy Company, without the transmission and electricity trading issues, we can objectively allocate the costs between the distribution and supply activities.

6. Cost allocation: distribution vs supply energy activity (regulated)

There are two methods of calculating costs that may be used in defining distribution costs. ***Average Cost Pricing*** is based on the existing total cost allocated to units (energy or demand) transported through networks. ***Marginal Cost Pricing*** is based on future costs necessary to transport one kW or kWh through the networks. The average cost approach differs from the marginal cost approach, in that the latter one show how costs would change if there is an increase or decrease of energy used in a certain period of time. It is a forward looking and hypothetical exercise, which mostly requires revenue reconciliation by the following alternative approaches:

- *Ramsey pricing* (inverse elasticity rule) - differential adjustment to overall class cost assignments based on relative demand elasticity;
- *Differential adjustment of marginal cost components* - differential adjustments to the energy, demand or customer cost components of the allocation based on their relative demand elasticity;
- *Equi-proportional adjustment of class marginal cost assignment method* entails increasing and decreasing marginal cost revenue for each class by the same proportion to conform the allocation to rate making revenue requirement.

  K (adjustment factor) = 1 + (Revenue requirement – Marginal cost revenue) / System marginal customer related cost revenue; Total revenue = Marginal cost revenue class * K.
- *Lump-sum transfer adjustment method* involves setting all rates to marginal cost and making up the difference between the revenue requirement and marginal cost revenues through a surcharge or rebate added to the bill.

  K (adjustment factor) = System revenue requirement / System Marginal cost revenue.

The pros and cons of these two methods are:

2 table. Comparison of the Average and Marginal Cost Methods

Average Cost Pricing	Marginal Cost Pricing

Advantages	Advantages
- Costs easily identified - Revenue requirements coverage and financial viability of network service providers ensured	- Reflects the major economic rules and creates proper efficiency signals - Prices signal the economic costs of consumption and investment decision
Disadvantages	Disadvantages
- Poor cost signal for efficient consumption - Subjective choice of allocation factors	- Derivation of marginal cost arbitrary or more difficult to implement - Additional mechanisms to ensure cost coverage might be necessary or always a need to reconcile marginal cost revenues to those allowed

There are various methods of distribution and supply cost allocation, depending on which pricing approach – average or marginal – is chosen (3 table).

3 table. Distribution and Supply Cost Allocation Methods

Average Cost Pricing	**Marginal Cost Pricing**
DISTRIBUTION A-CLASSIFICATION - Minimum Size Method - Minimum Intercept Method - Direct & Non-direct Cost Attribution B- ALLOCATION - Development of Distribution Demand Allocations - Allocation of Customer Related Costs	*DISTRIBUTION* A- COSTING METHODOLOGIES - Minimum Grid Methodology - Customer Specific Equipment Methodology B- MARGINAL CAPACITY COST C-ALLOCATION OF COSTS TO TIME PERIODS
CUSTOMER RELATED - Customer Related Costs in Distribution Function - Plant/Labor Method	*CUSTOMER RELATED* (COSTING METHODOLOGIES)

AVERAGE (EMBEDDED) COST APPROACH:

DISTRIBUTION:

A- CLASSIFICATION

i- The Minimum Size Method: The minimum size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the customer. The Minimum size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined, for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and the customer-related costs.

ii- The Minimum Intercept Method: The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and

extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.

Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method.

iii - Direct&non-direct cost attribution method is described at the end of this section.

B- ALLOCATION

i- Development of the Distribution Demand Allocators: There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Local area loads are the major factors in sizing distribution equipment. Consequently, customer class non-coincident demands and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

ii- Allocation of Customer-related Costs: The allocation of the customer-related portion of the various plant accounts is based on the number of customers by class of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

CUSTOMER RELATED:

i- Customer Related Costs in Distribution Function: The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.

ii- Plant/Labor Method: a less common approach is called plant/labor method that functionalizes customer accounts, customer service, and sales expenses according to the previously determined functionalization of utility plant and labor costs. The amount of payroll costs in generation, transmission and distribution-related operation and maintenance expenses determine the labor component of this functionalization. Since the majority of a utility's labor costs tend to be in distribution, the plant/labor method will tend to emphasize the distribution functionalization of customer accounts, customer service, and sales expenses.

<u>MARGINAL COST APPROACH:</u>

DISTRIBUTION:

A- COSTING METHODOLOGIES:

i- Minimum Grid Methodology: The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a hypothetical system that would serve all customers with voltage but no power (or with minimum demand of 0,5 KW), yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculation can be based either on the system as a whole or on a

sample of areas reflecting different geographical, service and customer density characteristics.

ii- Customer Specific Equipment Methodology: Most analysts agree that distribution equipment uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution cost and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest one. Beyond the customers' premises, however, there are distribution costs that may be classified as customer related. For example, some jurisdictions classify line transformers as customer-related often using a proxy based on average load as the allocation factor when this equipment is not uniquely dedicated to individual customers. In addition, for very large customers, more than merely meters, services, and transformers are directly assignable. Some have entire substations dedicated to them.

iii- The Zero Intercept Method: The third most common approach to calculate the customer related component in marginal as well as embedded studies is the zero intercept method. The measured relationship for each voltage level is expressed by the equation;

$$\text{Total Distribution Cost} = \alpha + \beta\ (\text{demand on distribution}) + \lambda\ (\text{customers})$$

The statistical difficulty with this equation is that the demand is highly correlated with the number of customers (multicollinearity) and that therefore it is not possible to identify the separate marginal effects of changes in demand and customer on cost.

$$\text{Total Distribution Cost} = \alpha + \beta\ (\text{demand on distribution})$$

It solves the multicollinearity problem by eliminating the customer variable under the hypothesis that the constant "ß" will then represent the non-variable, non-demand related portion of the costs, or the distribution facilities required when demand is zero.

B. MARGINAL CAPACITY COST:

To calculate the marginal demand related distribution cost for a particular customer class, the analyst needs to determine, using available load data, the increase in peak demand on the distribution system due to 1 kW increase in the maximum demand of the class. The peak demand on the distribution system is referred to as the non-coincident peak demand.

C. ALLOCATION OF COSTS TO TIME PERIODS:

Most analysts assume that the customer related marginal distribution costs don't vary by season or by time of day. Loads research at the distribution substation transformer level has indicated in a number of jurisdictions, however, those different segments of the distribution network peak at different times in the day and year, and are not closely related to the system peak. Those jurisdictions may find it more appropriate to adopt an equal allocation of distribution capacity costs or to allocate costs based on either the proportions of the number substations that peak during the individual costing periods, or by relating the amount of distribution investment to the timing of the peak demand where the investment was made.

CUSTOMER RELATED:

i- Most analysts assume that in current dollars there is little incremental change in the cost of customer related facilities and expenses. Since customer related facilities are added in small increments and exhibit little technological change, the effects of vintaging and

technological change, which normally distinguish marginal and embedded costs are reduced.

ii- While a case could be made that there are seasonal variations to such customer accounts as meter reading and customer information, the data is typically not analyzed on a monthly basis and there is no attempt at seasonal differentiation in the cost studies.

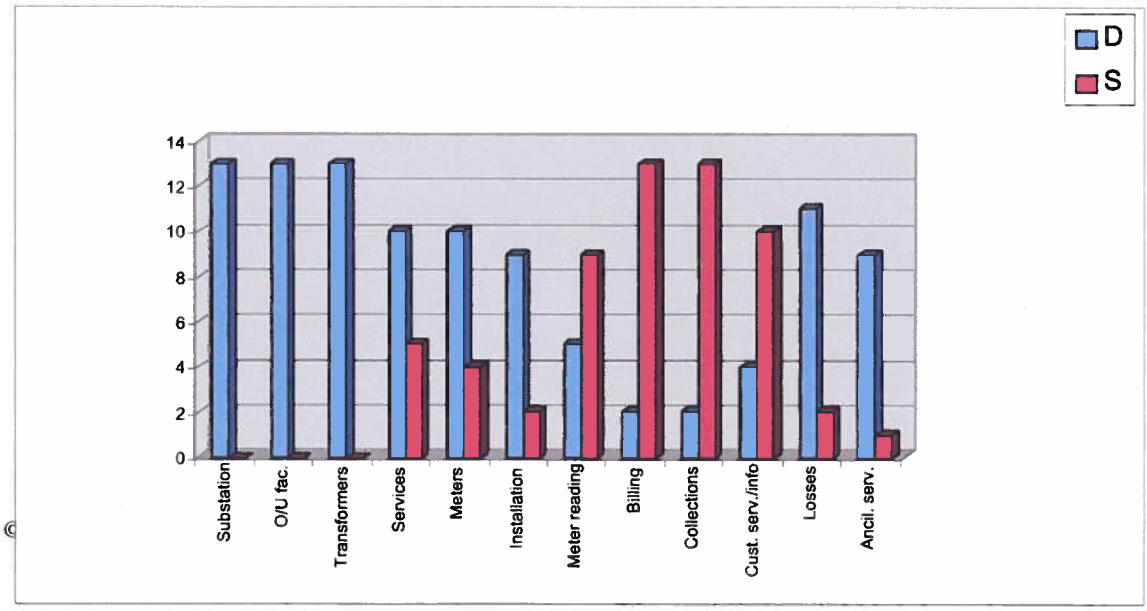
However, as we will see from the survey answers, reported below and in Section 9, the simple ***Average Cost Pricing*** or average historical cost approach is used by most countries for both distribution and supply pricing. According to the survey answers, another common approach used for allocating the distribution and supply cost is the – ***Direct & non-direct cost attribution***, as shown below (4 table).

4 table. Cost Attribution for Distribution and Supply Activities by Countries (Number of Answers)

Name of costs	Distribution	Supply
Substation	100%	0%
Overhead and Underground facilities, such as lines and conductors	100%	0%
Line Transformers	100%	0%
Services	67%	33%
Meters	71%	29%
Installation on Customer premises	82%	18%
Meter reading	36%	64%
Billing	13%	87%
Collections	13%	87%
Customer service and information expenses	29%	71%
Losses	85%	15%
Ancillary services	90%	10%
TOTAL of D&S costs	**63%**	**37%**

Graphically we can see the number of country answers, according to the type of costs that belong to the distribution or supply functions (2 pic.).

2 pic. Cost Attribution for Distribution and Supply Activities by Countries



(Number of Answers)

According to the results, the part of distribution costs in the total DSO cost is about 63% while the remaining 37% is related to the customer services supply cost.

7. Cost allocation of distribution to customer classes

Customer classes could be formed on the basis of their voltage level, capacity, consumption, activity types, etc., but also it could be done on the basis of the load factor (ratio of the average consumption with maximum consumption). This coefficient shows how efficiently consumers use their ordered capacity. Cost allocation according to this factor could send better signals to the consumers, showing that they should use their capacity more of the time, refuse it, or be willing to pay for capacity that is available but unused.

The cost could be allocated, using the proportion of the mentioned features in the whole amount. But we should be careful, that this does not make the tariff structure too complicated. Usually the customer classes consist of residential and the rest of the users, with some exceptions, such as for budget institutions, commercial businesses, agriculture, public lighting or other. Some of these classes may be temporary if they reach the needed effect or consumers adopt their consumption properly. In general, the customer classes reflect differentiation by voltage level (small consumers' devices are usually connected to the low voltage network, the larger – to the medium voltage network, the largest – to the high voltage grid). Cost allocation by voltage levels could be done on the basis of:

1. tangible fixed asset proportion;
2. volume of consumption proportion; or
3. other.

Tangible fixed asset proportions by voltage levels could be calculated taking numbers from the balance sheet. The survey results show that many ERRA member countries use fixed asset proportions to allocate costs among customers grouped by voltage level. The residential class may differ from other users, because these customers use more electricity during the minimum load time, i.e. their "night" load factor is higher than, for example, commercial consumers.

But of course, when deciding to make the proper tariff structure and then allocating costs to the customer classes, there is a need to look at the real energy system situation. The load graphics and their analysis will show the weak points of the current tariff structure or cost allocation, indicating where changes could be made to allow the sending of better signals to the consumers. The availability of will also determine the ability to make the needed tariff design, i.e. is there the right metering equipment, what data is available or possible to collect?

8. Cost allocation principles by tariff groups and other

, we may further differentiate tariff groups within the customer classes to establish more precise price signals. As was mentioned above, looking at the current situation and statistical analysis will help determine what other features should be taken into account to reduce the energy system costs

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and make electricity consumption more effective. Some of mentioned criteria, such as capacity, consumption, time, load factor and other, could be used if they were not already used when establishing customer classes. For example, we can make so-called tariff plans or groups using different load factors for the price of the concrete voltage level.

Trying to reflect the consumption and capacity variations, average electricity prices of the certain voltage level or prices of the certain tariff group, if they were made, could be differentiated as:

1. one-part tariff – all fixed and variable cost are reflected in one **energy** component (kWh);

2. two-part tariff – fixed cost or part of fixed cost are included in the **demand** component (kW), when variable or also some fixed cost could be reflected in **energy** component (kWh);

3. three-part tariff – without **energy** and **demand** components there are **abonent** component (per customer or per meter), which reflect a part of fixed cost, which are related with the consumer services (metering, billing, etc.).

The energy component also could be differentiated by time intervals: day and night or maximum, medium and minimum. The season factor could be applied too. The demand component could be also differentiated by load factor or its volume, if this was not applied in making customer classes or tariff groups.

Distribution costs are usually fixed, and just a small percent are variable. The most reasonable structure of this price is a two-part tariff with the demand and energy components. Usually the demand component reflects the fixed costs and the energy component – is variable. As it was mentioned, the fixed cost is a major part of distribution cost, and if we include all of it into the demand component, consumers could react negatively, or alternatively, it would be very expensive to use more capacity. So, moving to a price that reflects the fixed cost nature of the distribution system should be done gradually. Another option could be - about one fourth of the distribution costs treat as variable.

The cost allocation among these components is based on percentages, which usually differs a little in practice from the theoretical explanation. This difference between theory and practice is frequently due to a recognition that the customer's ability to pay is different from the allocated cost. For example, we have 100% of cost and wanting to calculate the abonent component, we separate all costs related to the customer services. The result is that the abonent component could be about one fifth of the total distribution cost.

The remainder of the distribution cost should be allocated between energy and demand components. Despite the fact that variable or energy related costs is a small part of the total cost - as technical losses mainly - in practice they could reflect about about half or more of the distribution cost in order to recognize customers' needs and their ability to pay. The remainder of the distribution costs may be attributed to the demand or capacity related component.

These three components also could be differentiated according to the various criteria:

- energy tariff – time, seasons, volume of consumption, consumer types, categories and other;
- demand tariff – time, seasons, volume of capacity, load factor, consumer types, categories and other; and
- abonent tariff – consumer types, categories and other. Abonent cost could be measured (divided) by number of meters or number of consumers.

How we combine all these variants and the tariff structure selected depends on the meter possibilities and data availability.

It should also be mentioned that all these tariffs should work together as one system. One has to be bear in mind, that if we change one component, others change automatically. This is especially important, if we still have two tariff structures – for vertically integrated systems and for the already competitive market.

9. Results of the questionnaire

In order to try to understand the situation regarding cost allocations in other countries, the questionnaire was prepared. We received 20 answers from 22 ERRA member country representatives of the tariff committee, all except Macedonia and Slovakia. Answers were based on 2004 data. In order to see the concrete answers of the countries, please, look at the abbreviations.

5 table. Abbreviations of the Countries Names

No.	Country	Abbreviation
1	Albania	AL
2	Armenia	AM
3	Bulgaria	BG
4	Croatia	HR
5	Estonia	EE
6	Georgia	GE
7	Kazakhstan	KZ
8	Kyrgyz Republic	KG
9	Latvia	LV
10	Lithuania	LT
11	Moldova	MD
12	Mongolia	MN
13	Montenegro	YU
14	Poland	PO
15	Romania	RO
16	Russian Federation	RU
17	Turkey	TR
18	Ukraine	UA
19	Hungary	HU
20	Bosnia & Herzegovina	BA

9.1. INDUSTRY STRUCTURE

In order to understand, what tariff structure or cost allocation is used by ERRA countries, we first need to look at what model and structure is applied to their electricity sector.

1. Which industry model is in your country?
   (a) Monopoly – 8 (AL, AM, HR, EE, KG, LV, YU, BA)
   (b) Single buyer – 5 (GE, MN, RU, UA, HU)
   (c) Wholesale competition – 6 (BG, KZ, LT, MD, PL, RO)
   (d) Retail competition – 2 (TR, HU)

2. What is the number of the market participants in your country?

No.	Country	G	T	D	IS	Other
1	Albania	1	1	1	0	0
2	Armenia	5	1	1	0	29
3	Bulgaria	1	1	8	0	3
4	Croatia	1	1	1	0	7
5	Estonia	4	1	42	1	0
6	Georgia	50	2	9	0	32
7	Kazakhstan	60	20	0	500	0
8	Kyrgyz Republic	1	1	4	0	3
9	Latvia	1	1	8	5	0
10	Lithuania	5	1	2	19	5
11	Moldova	5	1	5	2	2
12	Mongolia	5	1	0	0	0
13	Montenegro	1	1	1	0	0
14	Poland	20	1	14	10	0
15	Romania	40	1	8	80	0
16	Russian Federation	120	1	80	60	80
17	Turkey	17	1	8	8	0
18	Ukraine	27	1	36	58	0
19	Hungary	1	1	6	23	0
20	Bosnia&Herzegovina	3	3	3	0	0
	TOTAL	**368**	**42**	**237**	**766**	**161**

3. What is the level of unbundling in your country?

Meanings: c – separate company, a – separate account, c/a – separate company and account and o – other

No.	Country	G	T	D	S
1	Albania	0	0	0	0
2	Armenia	c	c	c	0
3	Bulgaria	c	c	c	a
4	Croatia	c	c	c	c
5	Estonia	c	c	c/a	c/a
6	Georgia	c/a	c/a	c/a	0
7	Kazakhstan	c	c	c	c/a
8	Kyrgyz Republic	c/a	c/a	c/a	0
9	Latvia	a	c	a	a
10	Lithuania	c	c	a	c/a
11	Moldova	c/a	c/a	c/a	0
12	Mongolia	c/a	c/a	c/a	c/a
13	Montenegro	a	a	a	a
14	Poland	c/a	c	a	c/a
15	Romania	c/a	c/a	a	c/a
16	Russian Federation	c/a	c	c/a	a
17	Turkey	c	c	a	a
18	Ukraine	c/a	c/a	c/a	c/a
19	Hungary	c	c	a	a
20	Bosnia&Herzegovina		c/a		

4. What is the declared market opening in your country?

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(a) ≤ 20% - 8 (AL, HR, EE, GE, MN, YU, RU, BA)
(b) 20-70% - 4 (BG, HU, LV, TR)
(c) ≥ 70% - 5 (KZ, LT, MD, PL, RO)
(d) No market – 3 (AM, KG, UA)

5. What is the real market opening in your country?
(a) ≤ 20% - 14 (AL, BG, HR, EE, GE, LV, LT, MD, MN, YU, PO, RU, TR, BA)
(b) 20-70% - 2 (HU, RO)
(c) ≥ 70% - 1 (KZ)
(d) No market - 3 (AM, KG, UA)

9.2. REGULATED TARIFFS, PRICE CONTROL METHODS AND PRINCIPLES

1. What separate prices are in your country?

No.	Country	G	T	D	S	B	Other
1	Albania	1					End user tariffs
2	Armenia	1	1	1	0		MO
3	Bulgaria	1	1	1	0	1	
4	Croatia		1	1			
5	Estonia	1	1	1	1		
6	Georgia	1	1	1			DC
7	Kazakhstan	1	1	1	1	1	
8	Kyrgyz Republic	1	1	1			
9	Latvia	1	1	1	1	1	
10	Lithuania	1	1	1	1	1	PSO
11	Moldova		1	1	1		
12	Mongolia	1	1	1	1	0	DC
13	Montenegro	1	1	1	1		TSO, MO
14	Poland	1	1	1	1		
15	Romania	1	1	1	0	1	MO
16	Russian Federation	1	1	1	in future	in future	
17	Turkey	0	1	1	1	1	SB price
18	Ukraine	1	1	1	1		
19	Hungary	1	1	1	1	1	
20	Bosnia & Herzegovina	Tariff structure considers bulk price including all mentioned prices					
	TOTAL	**16**	**18**	**18**	**11**	**7**	

2. Who forms the principles of the concrete/final tariffs to the consumers?

No.	Country	Company	Regulator	Ministry
1	Albania		1	
2	Armenia		1	
3	Bulgaria		1	
4	Croatia		1	
5	Estonia	1 - supply	1 - T&D	
6	Georgia		1	
7	Kazakhstan		1	
8	Kyrgyz Republic		1	
9	Latvia	1	1	
10	Lithuania	1		
11	Moldova		1	
12	Mongolia		1	

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13	Montenegro		1	
14	Poland			1
15	Romania		1	
16	Russian Federation		1	approves
17	Turkey	1	1	
18	Ukraine		1	
19	Hungary		1 - prepares	decides
20	Bosnia &Herzegovina		1	
	TOTAL	**4**	**18**	**1**

3. Who approves the concrete/final tariffs to the consumers?

No.	Country	Company	Regulator	Ministry	Other
1	Albania		1		
2	Armenia		1		
3	Bulgaria		1		
4	Croatia				Government
5	Estonia	1	1 - T&D		
6	Georgia		1		
7	Kazakhstan			1	
8	Kyrgyz Republic		1		
9	Latvia		1		
10	Lithuania	1	1		
11	Moldova	1 - IS	1		
12	Mongolia		1		
13	Montenegro		1		
14	Poland		1		
15	Romania		1		
16	Russian Federation		1		
17	Turkey		1		
18	Ukraine	1	1		
19	Hungary		1 - prepares	decides	
20	Bosnia & Herzegovina		1		
	TOTAL	**4**	**18**	**1**	**1**

4. What method is used for setting services price?
1 – price cap, 2 – revenue cap, 3 – price/revenue cap, 4 – cost plus

No.	Country	G	T	D	S
1	Albania				1
2	Armenia	4	4	4	
3	Bulgaria	4	4	2	2
4	Croatia	n/a	n/a	n/a	n/a
5	Estonia	1	4	4	1
6	Georgia	4	4	4	
7	Kazakhstan	market	1/4	1/4	adjustment
8	Kyrgyz Republic	1	1	1	
9	Latvia	1	1	1	1
10	Lithuania	1/4	3	3	1
11	Moldova	4	4	4	
12	Mongolia	4	4	4	4
13	Montenegro	2	2	2	2
14	Poland		4	2	2
15	Romania	4	2	1	profit margin
16	Russian Federation	4	3/4	3/4	3/4

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17	Turkey	2	2	3	1
18	Ukraine	offers	4	4	4
19	Hungary		1/4	1/4	1/4
20	Bosnia & Herzegovina	4	4	4	4

Notes: Albania - They approved price cap methodology which will be applied since 2006;
Russia – cost plus is applied for guaranteed supplier;
Turkey – cost plus in practice for all separated prices;
Hungary - starting prices are cost based, in remaining years of regulation period prices are changing by formulae, containing efficiency factor.

5. How the price or revenue cap applied?

No.	Country	Voltage levels	Customer groups	Tariffs plans	Other
1	Albania	1	1		
2	Armenia				
3	Bulgaria	1	1		
4	Croatia				
5	Estonia	1	1		
6	Georgia				
7	Kazakhstan	1			
8	Kyrgyz Republic			1	
9	Latvia				
10	Lithuania	1			
11	Moldova				
12	Mongolia				
13	Montenegro			1	
14	Poland				total revenue of the company
15	Romania	1	1		
16	Russian Federation				total revenue of the company
17	Turkey	1	1		
18	Ukraine	1	1		
19	Hungary				1
20	Bosnia & Herzegovina				
	TOTAL	**8**	**6**	**2**	**3**

Note: In Hungary price cap is applied to nationwide average price of T&D and to nationwide average public end user price.

6. What criteria are evaluated in the "cap" formula?

No	Country	Inflation	Efficiency	Volume	Unpredicted changes	Under/over recovery	Quality	Other
1	Albania		1					
2	Armenia							
3	Bulgaria	1	1	1			1	
4	Croatia							
5	Estonia	1	1	1	1	1		
6	Georgia							
7	Kazakhstan	1		1	1			
8	Kyrgyz Republic	1	1	1			1	obligations, capital cost
9	Latvia	1	1		1			
10	Lithuania	1	1	1	1	1	1	
11	Moldova							

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12	Mongolia							
13	Montenegro	1	1					
14	Poland	1	1					
15	Romania	1				1	1	
16	Russian Federation	1		1	1	1		
17	Turkey	1	1	1	1	1	1	
18	Ukraine	1	1	1	1			
19	Hungary	1	1		1		1	
20	Bosnia & Herzegovina							
	TOTAL	**13**	**11**	**8**	**8**	**5**	**6**	**1**

Notes: 1. Estonia – if company does not make promised investments, the under/over revenue recovery coefficient could be applied.

2. Kazakhstan – there is a possibility for to evaluate a volume adjustment and unpredicted changes coefficients.

7. If there is applied incentive-based method, what is the regulatory period?

No.	Country	1 year	3 years	5 years	Other
1	Albania		1		
2	Armenia				
3	Bulgaria			1	
4	Croatia				
5	Estonia		1		
6	Georgia				
7	Kazakhstan		1		
8	Kyrgyz Republic	1			
9	Latvia		1		
10	Lithuania	1	1		
11	Moldova				
12	Mongolia				
13	Montenegro	1			
14	Poland		1	1	
15	Romania			1	
16	Russian Federation	1			
17	Turkey			1	
18	Ukraine				
19	Hungary				1
20	Bosnia & Herzegovina				
	TOTAL	**4**	**6**	**4**	**1**

Notes: 1. Bulgaria and Romania – it was 3 years for the first regulatory period.
2. Lithuania – 1 year price cap is applied only for the public tariffs (integrated price).
3. Russian Federation – with 3 year prognosis.
4. Hungary – 4 years.

8. Is the profit sharing mechanism applied?
   (a) Yes – 6 (KG, LT, PL (will be), RO (except the first regulatory period), UA, HU)
   (b) No – 14 (the rest)

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9. What is the distribution pricing methodology?
   (a) Average cost - 18
   (b) Marginal cost – 2 (TR, BA)

10. What is the supply pricing methodology?
   (a) Average cost - 19
   (b) Marginal cost – 1 (BA)

11. In case of marginal cost, what is the form of adjusting marginal costs applied in order to satisfy the revenue requirement? (please, see explanations below)
   (a) Ramsey pricing
   (b) Differential adjustment of marginal cost components – 1 (BA)
   (c) Equi-proportional adjustment of class marginal cost assignment
   (d) Lump-sum transfer adjustment – 1 (TR)

12. What principle is used to separate supply activity costs from the distribution costs?
   (a) Direct & non-direct cost attribution – 13
   (b) The Minimum Grid Method – 1 (TR)
   (d) Proportion of the fixed asset – 3 (PL, HU, BA)
   (c) Other – 3 (EE, KZ, YU)

13. If there is applied Direct & non-direct cost attribution, which below ***costs*** are included by activity type?

Name of costs	Distribution	Supply
Substation	13	0
Overhead and Underground facilities, such as lines and conductors	13	0
Line Transformers	13	0
Services	10	5
Meters	10	4
Installation on Customer premises	9	2
Meter reading	5	9
Billing	2	13
Collections	2	13
Customer service and information expenses	4	10
Losses	11	2
Ancillary services	9	1
Others	0	0
TOTAL ANSWERS	101	59

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9.3. TARIFF CLASSIFICATION, COST ALLOCATION TO USERS AND TARIFF STRUCTURE

1. Table. Electricity Prices Differentiation

No	Differentiation	Generation price	Transmission price	Distribution price	Supply price	Public price for residential consumers (non eligible)	Public price for other consumers (non eligible)
1.	By voltage levels		6	13	3	6	14
2.	By seasons		2	2	2	2	5
3.	By tariffs plans	2	2	3	3	4	6
4.	By customer groups		2	4	3	7	9
5.	Other (please, explain)		1	1	1	2	2
6	**For residential consumers:**						
6.1	For residential consumers, having electric stoves			1	1	8	2
6.2	For residential consumers, using comparably a big amount of electricity (>12 000 kWh)			1	1	4	3
6.3	Other (please, concrete)	1		1		2	
7.	**One-part tariff:**						
7.1	Single tariff	3	5	7	8	11	10
7.2	Day and night tariff			3	4	9	9
7.3	Differentiated tariff (>2 time intervals)			1	2	2	7
7.4	Other (please, concrete)						
8.	**Two-part tariff:**						
8.1	Energy and demand component	6	5	5	4	2	7
8.2	Energy and abonent component					3	2
8.3	2 time energy component and demand component			1			4
8.4	2 time energy component and abonent component			1		1	2
8.5	>2 time energy component and demand component			1			3
8.6	>2 time energy component and abonent component					1	1
8.7	Other (please, concrete)		1			1	
9.	**Three-part tariff:**						
9.1	Energy, demand and abonent components		1	3		2	3
9.2	Differentiated energy, demand and abonent components			1	1	1	2
9.3	Differentiated energy,						1

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	differentiated demand and abonent components						
9.4	Differentiated energy, differentiated demand and differentiated abonent components						1
10.	Reactive Energy	1	2	4	2		7
11.	Other						

Notes:
1) Differentiation by seasons – PL, UA, HR, RO, BA.
2) Differentiation by tariff plans – KG, RU, HR, LT, EE.
3) Residential tariffs with electric stoves – UA, BG, MD, KG, LT, HU, BA, RU.

4) Two-part tariff for:
- generation price – BG, GE, AM, EE, LT, RU;
- transmission price – YU, AM, EE, LT, RU, TR (only demand component);
- distribution price – YU, KG, EE, LT, RU;
- supply price – KZ, TR, KG, EE;
- integrated price (with all above mentioned services) – RO, KG, LV, LT, HU, BA, RU.

5) Three-part tariff for:
- generation price – -;
- transmission price – HR;
- distribution price – HR, EE, HU;
- supply price – YU, HR;
- integrated price – YU, HR, LV.

6) Reactive energy price or cost included in:
- generation price – YU;
- transmission price – HR, TR;
- distribution price – PL, HR, TR, HU;
- supply price – PL, TR;
- integrated price – PL, HR, RO, LV, LT, HU, BA.

2. What the customer groups exist in your country?
(a) Residential – 16 (except AM, EE, KZ, MD)
(b) Agriculture – 2 (RU, TR)
(c) Public lightening – 8 (BG, HR, LV, YU, RU, TR, HU, BA)
(d) Other (mostly industrial & commercial customers and by voltage levels) – 19 (except KZ).

Additional groups:
- Albania – Budgetary, non-budgetary, media, private, favored private (bakery, flour production, pumping stations;
- Kyrgyz Republic – state budgetary organizations;
- Montenegro - non-residential with demand metering and non-residential without demand metering;
- Russian Federation - >20MW;
- Turkey - government organizations.

3. What principle is used to allocate distribution costs according to the voltage levels?
(a) Proportion of the fixed asset - 11
(b) Proportion of the consumption – 3 (KG, PL, HU)
(c) Other – 3 (AM, EE, KZ). No answer from AL, HR, MD)

4. Is Distribution charge structure based on Use of network charge and Connection charge?
   (a) Yes – 10 (BG, HR, LT, YU, PL, RO, RU, TR, HU, BA)
   (b) No – 7 (the rest, except no answer from AL, AM, EE)

5. If yes, which approach is considered to determine connection charge?
   (a) Deep connection charges – 5 (HR, LT (for generators and temporary consumption), PL, RO, HU, BA)
   (b) Shallow connection charges – 6 (BG, LT, YU, RU (deep connection in the future probably), TR, HU)
   (c) Others – 3 (KZ (charge for additional capacity, when tariff is lower than usual), LV (share of real connection costs to distribution network), HU (mixed: connection charge depends on available/contracted capacity, and on length of new network to be built.))

6. What principle is used to allocate demand-related distribution costs according to customer group?
   (a) Coincident Demand Peak - 4 (KG, MN, RU, TR)
   (b) Non – Coincident (Individual Demand Peak) - 1 (BA)
   (c) Mixed Approach – 3 (LT, PL, HU)
   (d) Others – 2 (KZ (for industry customers with more than 750 kVA), MN (individual demand peak in the sum of individual demand peaks of the referent voltage level))

7. What principle is used to allocate energy-related distribution costs according to customer group?
   (a) Energy consumption – 14 (except AL, AM, EE, YU, MD, TR)
   (b) Others – 1 (GE – by voltage levels)

8. What principle is used to allocate customer related distribution costs according to customer group?
   (a) Number of meters – 5 (BG, YU, PL, TR, HU)
   (b) Number of customer – 4 (LT (most probably), MN, PL, BA)
   (c) Others – 3 (AM, KG, UA)

9. If there are different tariff plans for the same consumer group, what criteria are used to separate them?
   (a) Volume of consumption – 4 (AL, KG, LV, RO)
   (b) Load factor – 3 (LV, LT, HU)
   (c) Maximum capacity – 2 (LV, MN)
   (d) Other – 2 (HR, UA)

10. How much of transmission costs is covered by demand (fixed) component?
    (a) ≤ 20% - 1 (KG)
    (b) 20-50% - 1 (AM)
    (c) ≥ 50% - 5 (EE, LT, YU, PL, RU)
    (d) No fixed component - 13

11. How much of distribution costs is covered by demand (fixed) component?
    (a) ≤ 20% - 4 (KG, LV, LT, HU)
    (b) 20-50% - 4 (EE, PL, HU, BA)
    (c) ≥ 50% - 2 (YU, RU)
    (d) No fixed component - 14

12. If there is a demand (fixed) charge, what meaning is used?
    (a) Actual peak capacity – 3 (LT, YU, BA)
    (b) Ordered capacity – 5 (AM, KG, PL, RU, UA)
    (c) Maximum allowed capacity – 3 (HR, LV, LT)
    (d) Main fuse – 2 (LV, HU)
    (e) Other – 2 (EE, TR)

13. How higher is the residential average price comparing with the industrial average price?
    (a) ≤ 25% - 10
    (b) 25-50% - 3 (AM, GE, PL)
    (c) Other – 7 (AL (lower than industrial average price), EE (same level), KZ (residential price 50% higher wholesale industry price, but it could be lower if compare with small industry (<2MW) price), KG (54%, due to cross-subsidization), MN (same level), YU (industry price is about 90% higher residential price), RU (same level), UA (residential price is twice lower than industry price))

14. Are there foreseen changes of electricity tariffs structure in the nearest future?
    (a) Yes - 15
    (b) No – 5 (AM, HR, EE, RU, HU)

15. How frequent is the revision of electricity prices?
    (a) Annually – 12 (AL, AM, EE, LV, LT, MD, MN, PL, RU, TR, HU, BA)
    (b) Once setting the price cap – 4 (BG, EE, YU, HU)
    (c) Other – 6 (HR (not defined), GE (if necessary), KZ (twice per year), KG (annually - setting the prices for companies, but the final customers - they were set 5-6 years ago), RO 9twice per year), UA (depends on company))

16. Are there foreseen to increase electricity prices in the nearest future?
    (a) Yes - 13
    (b) No – 6 (AM, HR, EE, GE, MD, TR). No answer from AL.

10. Final comments

Distribution and supply cost allocation is an urgent issue recently, as there is a desire for more transparency and objectivity in the distribution activity. As described in the section 6, different

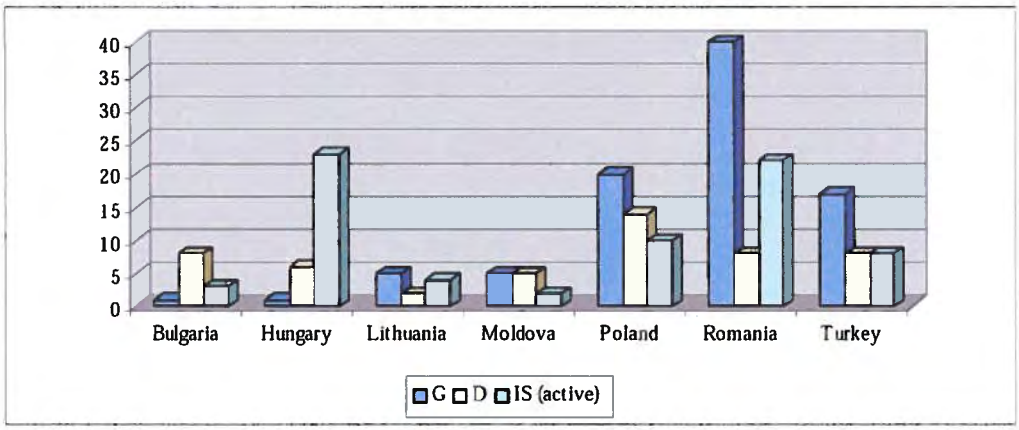
methods for trying to separate distribution and supply functions may be applied. But, most countries have chosen the Direct & non-direct cost attribution method. Despite the fact that this method is not precise, it is popular, because of its easy applicability.

Public Supplier prices or future Supplier of Last Resort prices could be set in a different way, if we separate this activity from the distribution company. At the moment there is no such legal requirement in the countries, but different methods could be applied setting or regulating the price for this activity: tenders, regulated price, selection in the competitive market, auctions and other. So, it depends on the countries' legal provisions about this activity.

Distribution and supply cost attribution or differentiation sends the economic signals to the consumers. Fixed and variable costs reflected within the demand, energy and abonent components helps to show the cost causality, and makes the use of energy system more efficient. It seems, most ERRA countries have chosen this way, despite the problematic introduction of such a tariff structure to the consumers.

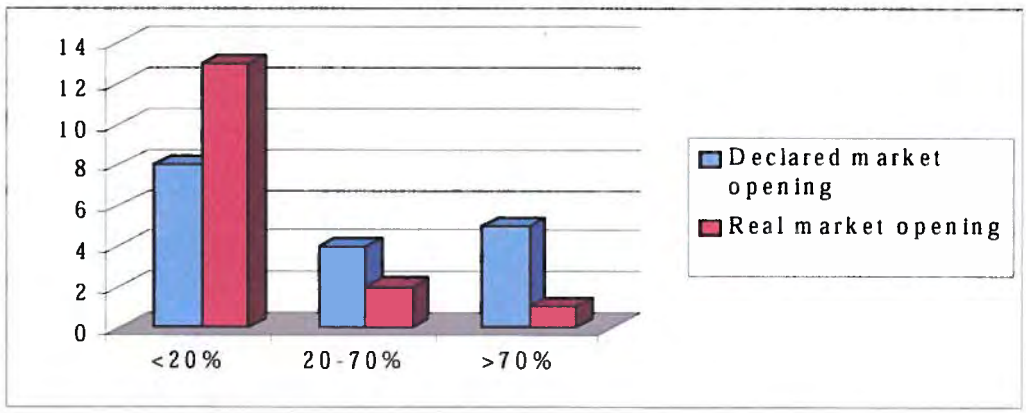
In order to see what the whole situation in the ERRA countries is on this issue, the questionnaire was prepared. As it is possible to see from the answers, nearly one-half of the ERRA countries have taken steps towards a more developed market -- with up to 20% real opening of competition. Other countries still have monopoly or single buyer models. Also, as it is possible to see from the picture below, only a few countries have competitive conditions in the generation or supply sectors.

3 pic. Market Participants' Number in 2004



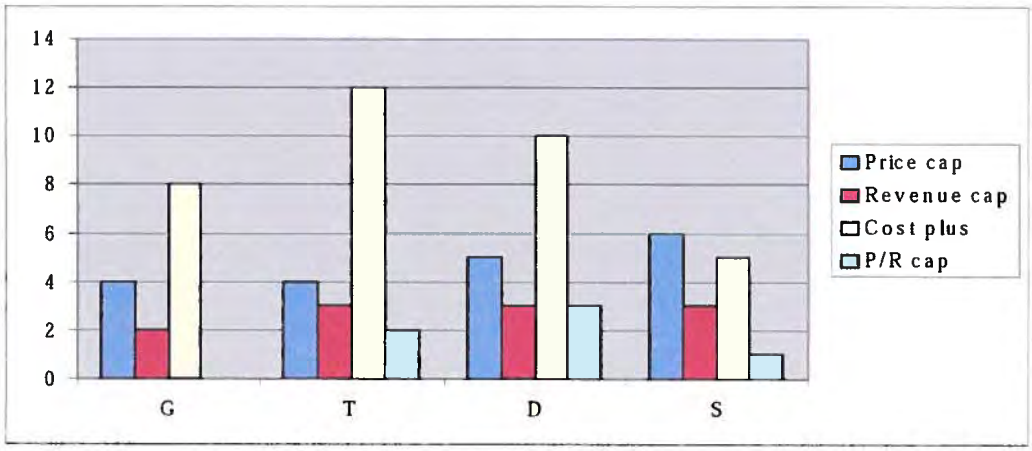
This is probably one of the reasons, that most of the countries declare the higher market opening, but in reality the switching number is low.

4 pic. Declared and Real Market Opening by Number of Countries in 2004



The methods applied to calculate electricity prices are different in the countries. The cost plus method still remains a popular regulation tool. The "cap" approach is also used in many cases..

5 pic. Methods Applied by Number of Countries



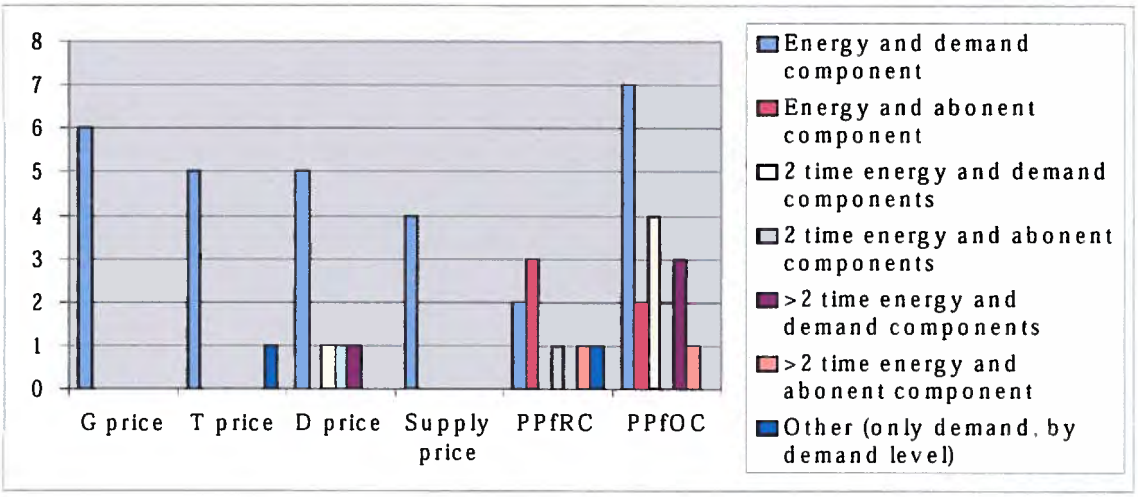
The price or revenue caps are applied to the different voltage levels, and just in some countries to the customer groups and even the tariff plans. As the rule, most countries apply inflation, efficiency, volume adjustment and contingency factors. Six countries apply the quality requirement factor and four countriesuse the under/over revenue recovery factor. Profit sharing mechanisms are also applied in one-third of the countries. The incentive based principle applied mostly for the 3 years period, but it is possible to see the tendency towards longer durations, e.g., 5 years.

Some countries have chosen more complicated tariff structures, while others like a simplified form. Usually, the simpler form does not send the right signals to the consumers, but this structure is more understandable to the consumers.

Most of the countries have separate residential and industrial customer groups. Some countries have a separated state budget consumer group. The public lighting tariffs and electricity tariffs for residential consumers, using the electric stoves, are still popular in most ERRA member countries. The agriculture consumer group has mostly disappeared from the tariff structure, and only Kyrgyz Republic and Turkey apply tariffs for such a group.

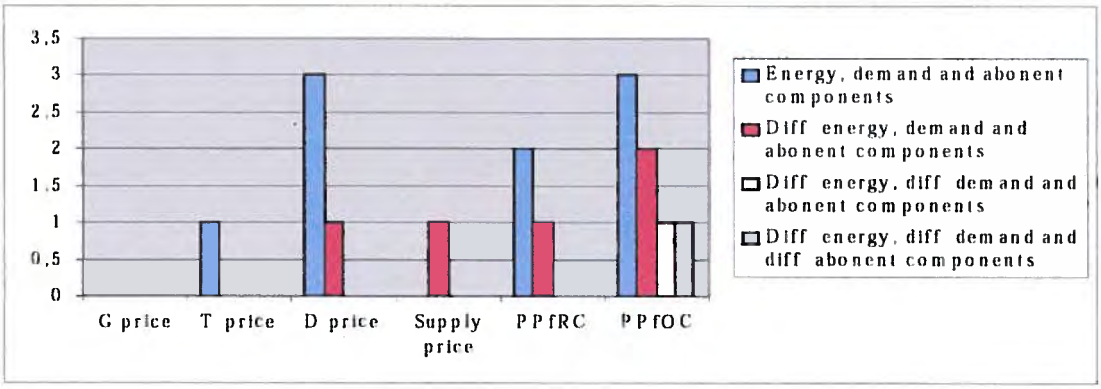
Further differentiation is done through the selection of the tariff type. There are different ways to structure the electricity tariff, including different ways to structure the two-part tariff, as shown in the picture below.

6 pic. Applied Two-part Tariff Type by Number of Countries



The variety of three-part tariff applications may be seen in the following picture.

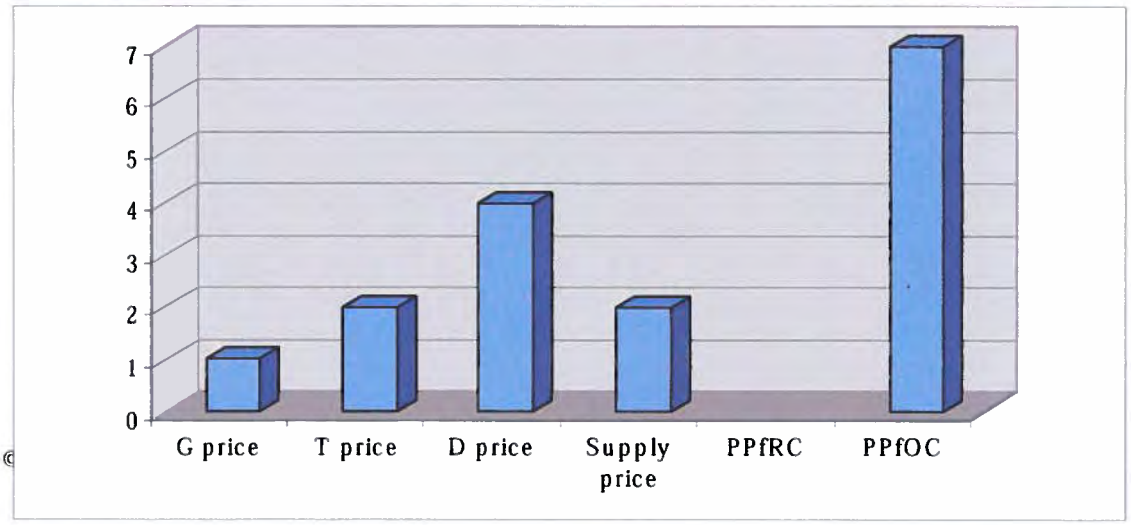
7 pic. Applied Three-part Tariff Type by Number of Countries



According to the answers to the questionnaire, the transmission demand component covers 50% and more of fixed costs, and the distribution demand component is up to 50% of the cost.

Applying the reactive energy price, we see the following view:

8 pic. Reactive Energy Price Application by Number of Countries



It is possible to see from the answers, that most of the Regulators revise or set prices annually. Fifteen countries (with the exception of Armenia, Croatia, Estonia, Russian Federation and Hungary) foresee changes in their electricity tariff structure in the nearest future. Thirteen countries are ready to increase the electricity prices in the nearest future, (with the exception of Armenia, Croatia, Estonia, Georgia, Moldova and Turkey and possibly Albania, who provided no response on this question.)

If one wishes to see more concrete details regarding each country, there are zipped files of all countries' answers, and it is possible to download them from the ERRA website.

11. Annex. Questionnaire on Allocation Cost & Methods

PART I - INDUSTRY STRUCTURE

1. Which industry ***model*** is in your country?
   (a) Monopoly
   (b) Single Buyer
   (c) Wholesale Competition
   (d) Retail competition

2. What is the ***number*** of the market participants in your country?

Activity	Number of companies
Bulk Production (Wholesaler)	
Transmission	
Distribution & Public Supply	
Retail (Independent Supply)	
Other	

3. What is the ***level*** of unbundling in your country? Please, mark by X.

Form	Generation	Transmission	Distribution	Supply
Separate Company				
Separate Account				
Others				

4. What is the ***declared*** market opening in your country?
   (a) $\leq$ 20%
   (b) 20-70%
   (c) $\geq$ 70%

5. What is the ***real*** market opening in your country?
   (a) $\leq$ 20%
   (b) 20-70%
   (c) $\geq$ 70%

PART II - REGULATED TARIFFS, PRICE CONTROL METHODS AND PRINCIPLES

1. What **separate** prices are in your country?
   (a) Generation
   (b) Transmission
   (c) Distribution
   (d) Supply
   (e) Balance energy
   (f) Other (please, concrete)

2. ***Who forms*** the principles of the concrete/final tariffs to the consumers?
   (a) Distribution (supply) company
   (b) Regulator
   (c) Ministry
   (d) Other (please, explain)

3. ***Who approves*** the concrete/final tariffs to the consumers?
   (a) Distribution (supply) company
   (b) Regulator
   (c) Ministry
   (d) Other (please, explain)

4. What ***method*** is used for setting services price? Please, mark by X.

Method	Generation	Transmission	Distribution	Supply
Price cap				
Revenue cap				
Price/revenue cap				
Cost plus				
Other (please, explain)				

5. ***How*** the price or revenue cap applied?
   (a) By voltage levels
   (b) By customer groups
   (c) By tariffs plans
   (d) Other (please, concrete)

6. What ***criteria*** are evaluated in the "cap" formula? Please, mark by X.
   (a) Inflation .....
   (b) Efficiency .....
   (c) Volume adjustment .....
   (d) Unpredicted changes (external factors) .....
   (e) Under/over revenue recovery .....
   (f) Quality requirements .....
   (g) Other (please, explain) .....

7. If there is applied incentive-based method, what is the regulatory ***period***?
   (a) 1 year
   (b) 3 years
   (c) 5 years
   (d) Other (please, explain)

8. Is the ***profit sharing mechanism*** applied?

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(a) Yes
(b) No

9. What is the distribution pricing ***methodology***?
   (a) Average cost
   (b) Marginal cost
   (c) Others (Please, explain)

10. What is the supply pricing ***methodology***?
    (a) Average cost
    (b) Marginal cost
    (c) Others (Please, explain)

11. In case of marginal cost, what is the ***form*** of adjusting marginal costs applied in order to satisfy the revenue requirement?
    (a) Ramsey pricing (please, see explanations below)
    (b) Differential adjustment of marginal cost components
    (c) Equi-proportional adjustment of class marginal cost assignment
    (d) Lump-sum transfer adjustment
    (e) Others (Please, explain)

Note:
1. ***Ramsey pricing (inverse elasticity rule)*** - differential adjustment to overall class cost assignments based on relative demand elasticity.
2. *Differential adjustment of marginal cost component* **- differential adjustments to the energy, demand or customer cost components of the allocation based on their relative demand elasticity.**
3. ***Equi-proportional adjustment of class marginal cost assignment*** method entails increasing and decreasing marginal cost revenue for each class by the same proportion to conform the allocation to ratemaking revenue requirement.

K (adjustment factor) = 1 + (Revenue requirement – Marginal cost revenue) / System marginal customer related cost revenue;

Total revenue = Marginal cost revenue class * K.

4. ***Lump-sum transfer adjustment*** method involves setting all rates to marginal cost and making up the difference between the revenue requirement and marginal cost revenues through a surcharge or rebate added to the bill.

K (adjustment factor) = System revenue requirement / System Marginal cost revenue

12. What ***principle*** is used to separate supply activity costs from the distribution costs?
    (a) Direct&non-direct cost attribution
    (b) The Minimum Grid Method
    (d) Proportion of the fixed asset
    (c) Other (please, explain)

13. If there is applied Direct&non-direct cost attribution, which below ***costs*** are included by activity type? Please, mark by X.

Name of costs	Distribution	Supply
Substation		
Overhead and Underground facilities, such as lines and conductors		

Line Transformers		
Services		
Meters		
Installation on Customer premises		
Meter reading		
Billing		
Collections		
Customer service and information expenses		
Losses		
Ancillary services		
Others (please, explain)		

PART III - TARIFF CLASIFICATION, COST ALLOCATION TO USERS AND TARIFF STRUCTURE

1. Please, mark by X the column and row matches.

Table. Electricity prices differentiation

No	Differentiation	Generation price	Transmi-sion price	Distribu-tion price	Supply price	Public price for residential consumers (non eligible)	Public price for other consumers (non eligible)
1.	By voltage levels						
2.	By seasons						
3.	By tariffs plans						
4.	By customer groups						
5.	Other (please, explain)						
6	**For residential consumers:**						
6.1	For residential consumers, having electric stoves						
6.2	For residential consumers, using comparably a big amount of electricity (>12 000 kWh)						
6.3	Other (please, concrete)						
7.	**One-part tariff:**						
7.1	Single tariff						
7.2	Day and night tariff						
7.3	Differentiated tariff (>2 time intervals)						
7.4	Other (please, concrete)						
8.	**Two-part tariff:**						
8.1	Energy and demand component						
8.2	Energy and abonent component						
8.3	2 time energy component and demand component						
8.4	2 time energy component and abonent component						
8.5	>2 time energy component and demand component						
8.6	>2 time energy component and abonent component						
8.7	Other (please, concrete)						
9.	**Three-part tariff:**						
9.1	Energy, demand and abonent components						
9.2	Differentiated energy, demand and abonent components						
9.3	Differentiated energy,						

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	differentiated demand and abonent components						
9.4	Differentiated energy, differentiated demand and differentiated abonent components						
10.	Reactive Energy						
11.	Other (please, concrete)						

2. What the ***customer groups*** exist in your country?
   (a) Residential
   (b) Agriculture
   (c) Public lightening
   (d) Other (please, explain)

3. What ***principle*** is used to allocate distribution costs according to the voltage levels?
   (a) Proportion of the fixed asset
   (b) Proportion of the consumption
   (c) Other (please, explain)

4. Is Distribution charge ***structure*** based on Use of network charge and Connection charge?
   (a) Yes
   (b) No

5. If yes, which ***approach*** is considered to determine connection charge?
   (a) Deep connection charges
   (b) Shallow connection charges
   (c) Others (Please, explain)

6. What ***principle*** is used to allocate demand-related distribution costs according to customer group?
   (e) Coincident Demand Peak
   (f) Non – Coincident (Individual Demand Peak)
   (g) Mixed Approach
   (h) Others (please, explain)

7. What ***principle*** is used to allocate energy related distribution costs according to customer group?
   (c) Energy consumption
   (d) Others (please, explain)

8. What ***principle*** is used to allocate customer related distribution costs according to customer group?
   (d) Number of meters
   (e) Number of customer
   (f) Others (please, explain)

9. If there are different tariffs plans for the same consumer group, what ***criteria*** is used to separate them?
   (a) Volume of consumption
   (b) Load factor

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(c) Maximum capacity
(d) Other (please, explain)

10. How much of ***transmission*** costs is covered by demand (fixed) component?
    (a) ≤ 20%
    (b) 20-50%
    (c) ≥ 50%
    (d) No fixed component

11. How much of ***distribution*** costs is covered by demand (fixed) component?
    (a) ≤ 20%
    (b) 20-50%
    (c) ≥ 50%
    (d) No fixed component

12. If there is a demand (fixed) charge, what ***meaning*** is used?
    (a) Actual peak capacity
    (b) Ordered capacity
    (c) Maximum allowed capacity
    (d) Main fuse
    (e) Other (please, explain)

13. How ***higher*** is the residential average price comparing with the industrial average price?
    (a) ≤ 25%
    (b) 25-50%
    (c) Other (please, explain)

14. Are there foreseen ***changes of electricity tariffs structure*** in the nearest future?
    (a) Yes
    (b) No

15. How ***frequent*** is the revision of electricity prices?
    (a) Annually
    (b) Once setting the price cap
    (c) Other (please, concrete)

16. Are there foreseen to ***increase*** electricity prices in the nearest future?
    (a) Yes
    (b) No

17. Please list below any ***other*** questions you would like us to answer in the paper.

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12. Bibliographies:

1. Winning Retail Strategies: Beyond Innovative Rate Design. June 1995, – Electric Power Research Institute.
2. Electricity Utility Cost Allocation Manual. January 1992, - NARUC.

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