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Order	KOSOVO, SERBIA AND MONTENEGRO ENERGY SECTOR TECHNICAL ASSISTANCE PROJECT II - GRANT. No. H048
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Project Synopsis

Project Title:

KOSOVO, SERBIA AND MONTENEGRO
ENERGY SECTOR TECHNICAL ASSISTANCE PROJECT II
WORLD BANK Grant No. H048

FEASIBILITY STUDY FOR THE KOSOVO B (KOSOVO) – KASHAR (ALBANIA) 400 KV TRANSMISSION INTERCONNECTION PROJECT

Project Objectives:

The overall objective of ESTAP II/1 project is to prepare and submit a feasibility study report of the selected and recommended line and substations of the Project. The report shall be in a form that can be presented to donors and lenders for financing of the interconnection.

The study is divided in two phases:

- **First phase:** Technical and economic comparison of all proposed interconnection alternatives and making recommendations for the decision making authorities in Kosovo and Albania regarding the selection of the preferred variant of 400 kV interconnection line.
- **Second phase:** the full feasibility study including: a) determination of potential energy exchanges between Kosovo and Albania; b) the line impact in improving energy exchange capabilities in SEE; c) functional/preliminary design and engineering, of the line and substations; d) Detailed quantity and cost estimate of the Project; e) economic and financial analysis of the Project; f) Detailed implementation strategy for interconnection and sample agreements for construction and operation g) preparation of the topographic survey and EIA reports; h) provide to KEK the software used and training in its use.

Contracting Party:

United Nations Interim Administration Mission in Kosovo (UNMIK)

Contractor

CESI, Centro Elettrotecnico Sperimentale Italiano G. Motta, Italy;

Project Recipient Representatives

United Nations Interim Administration in Kosovo (UNMIK)

Mr. Ognjen Markovic
Project Development and Donor Coordination Manager
UNMIK KTA, Energy Division

Project Starting Date:

5th October 2004

Project Duration

Nine (9) months

ACKNOWLEDGEMENT

There are many people in KEK, KESH, Kosovo and Albanian Ministry of Energy headquarters to thank for their detailed attention to the ESTAP II/1 Project.

We take this opportunity to acknowledge the important contribution of Prof. Sabri Limari Senior Political Adviser Ministry of Energy and Mining for his invaluable support throughout the project, and for having added many valuable suggestions regarding the development of a strategy for Kosovo's energy sector.

We wish to thank our many colleagues and friends, in particular Eng. Faik Nahi and the staff of the Strategic Development Directorate, Transmission Departments and System Dispatching Center of KEK for their assistance in collecting a large volume of data and information; and provided several constructive comments during line routing, environmental assessment impact of the new line and other issues related to the project.

Among my KESH colleagues, the special thanks must go to G Daci Director of Albanian TSO, Y. Demiraj Director of Transmission Division and G. Dini Chief of Engineering Department who provided information cooperated and give their contributions on the various phases of the project.

The ESTAP II/1 team wishes to acknowledge the valuable contribution of the Mr. Ognjen Markovic Project Development and Donor Coordination Manager (UNMIK KTA, Energy Division) and his staff, for his expert advices, suggestions, support and assistance, and the help by which he greatly facilitated the establishment of essential contacts in various institutions of energy sector in Kosovo.

The ESTAP team acknowledges the considerable support it has received from all the members of the Steering Committee, who have patiently followed the project and provided several constructive comments on the project.

9 Interconnection agreement, O&M rules and transmission tariff

9.1 Interconnection agreement

9.1.1 Introduction

Scope of work in this chapter was to prepare a model for the interconnection agreements between KEK and KESH that could be used for new interconnection 400 kK Kosovo (Kosovo) - Kashar (Albania).

It is in common practice in this region for interconnection agreement to follow with different stages of agreements in all period from decision of construction through construction works and finally after commissioning of connecting link. So, we prepared two types of Agreements:

1. Agreement of mutual co-operation during implementation of project, and
2. Interconnection Agreement on operation and maintenance rules.

Approach of Agreement development has been based upon case study for different projects in this region. All proposals have been defined in close cooperation with KEK and KESH experts.

9.1.2 Agreement of mutual co-operation during implementation of project

The purpose of the first Agreement is to follow all activities before commissioning the interconnection line and second one as Agreement with agreed rules for operation, maintenance and mutual utilization.

First Agreement model, reported in Annex 1, is intended as document, which enables mutual activities of both Transmission system operators and transmission system providers in the phases of studying, designing of project as well as during activities on construction of line.

The main parts of the firs agreement are:

- √ Purpose of Agreement,
- √ Exchange of information,
- √ Setting up a Steering Committee to supervise project implementation,
- √ Definition of costs and expenses,
- √ Duration and validity of the Agreement,
- √ Termination of project, and
- √ Choices of legislation, disputes and arbitration.

This Agreement is the basic document for all activities during the project implementation before commissioning of the interconnection project.

9.1.3 Interconnection Agreement on maintenance and operation rules

The second Agreement, reported in Annex 2, is very important mutual document for efficiently operation of interconnection after commissioning the link. It defines in detail maintenance procedures, operation modes, responsibilities for measurements, protection and information technology devices.

Second agreement is prepared for time after construction of interconnection to support interoperability between systems. Interconnection agreement consist important issues as mutual operation, maintenance, metering, protection and communication activities.

Concept of model is composed from following parts:

- √ Subject of the agreement

- √ Definition of operating rules
- √ Technical arrangement
- √ Operation of grid elements during normal and special operating conditions
- √ Maintenance planning
- √ Procedures of actions during maintenance works
- √ Natural forces (act of god)
- √ Duration of agreement
- √ Legal succession and arbitration
- √ Costs and expenses
- √ Liability
- √ Annexes with detailed data for interconnection.

This Agreement considers both lines between two power systems Kosovo and Albania, respectively.

The sample of Agreement is given in Annex 2

For operational use of this Agreement it is crucial to follow organizational framework of both systems. So, the corrections are needed after finishing the re-organization of systems.

9.2 Principles of network tariff models

9.2.1 Introduction

The main objective of network pricing is the recovery of network costs, plus a reasonable return on investment. These costs are mainly determined by the transmission infrastructure, a minor part is related to ancillary services such as voltage support or operating reserve. Both parts can be accounted together or (partly) separately. The cost terms to be recovered as well as their quantity often have to be recognised by regulators or other bodies because the network is usually considered to be a natural monopoly, where market driving forces do not exist or are not strong enough to provide efficient price signals. One essential requirement to network pricing results from the networks being natural monopolies: the charges must be verifiable for parties other than the network operator himself, and they must be non-discriminatory in a way that network users under equal conditions have to pay equal charges.

In addition to this, many further objectives can be tried to achieve when developing a network-pricing concept:

- To promote competition by presenting the network user a predictable, stable and practical-to-apply framework of charges. This comprises for instance:

that the charges are transparent in a way that they can be easily calculated or looked up by the network users with good accuracy in advance of negotiating a possible transaction in order to foresee the financial consequences,

that the determination rules of charges are transparent to all actors in order for them to get an impression under which circumstances the charges might fluctuate,

that fluctuations of charges are reasonably small in the short and medium term, at least if market actors are not given the opportunity of hedging against such fluctuations by means of financial contracts related to network charges, and

  - that the demand of information on the individual case of network access for calculation of the charges is reasonably low.

- To provide appropriate price signals towards efficient use of the network. According to economic theory, this can be achieved by making charges reflect as precisely as possible the costs caused by each individual network access (cost reflectivity).
- To provide appropriate price signals for the network operators towards efficient operation and expansion of the networks. The international experience however shows that this objective is very difficult to fulfil because it strongly interferes with the basic requirement of more or less complete network cost recovery.

It is important to recognise that these objectives are partly contradictory. In particular, a great amount of discussion about network tariffs is devoted to finding a balance between the objective to promote competition, demanding for simple pricing methods, and the objective of cost-reflectivity, usually aiming towards more complicated concepts.

This chapter will present different models for network usage particularly related to transmission network. In second part of chapter it will be prepared a recommendation for transmission network tariff approach for Kosovo and/or Albania in deregulated environment.

9.2.2 Tariff Components

Cost reflectivity requires a decomposition of the network-service in individual components describing sub-services. A most precise decomposition results in a list of tariff components with at least twenty items or more. The most important are the following:

- Use-of-system (depreciation of assets)
- Operation
- Losses
- Metering
- Reserve power
- Balance power
- Frequency control
- Voltage control / reactive power
- Black-start
- Congestion management

Some of these are connected to each other (e.g. reserve power and frequency control), others can be decomposed in even smaller fractions. The most important task is to find structure which fulfils the above-mentioned requirements. Some principles for structuring the tariff components are:

Causation principle: Allocate costs to the one who causes them whenever possible. Example: Metering, reserve power, congestions.

- Cost reflectivity: Consider the individual characteristic of the components when putting them together. Example: Charges, which are mostly power- or energy-related.
- Simplicity: Reduce the number and complexity of components as much as possible. Example: Put together use-of-system, losses, and frequency-control, others in one charge.

These principles are contradictory to a certain degree, a suitable balance has to be found e.g. by comparing the expected market-incentives of different structures. It has to be stressed here, that simplicity has usually high priority in order to support a lively market.

9.2.3 Cost allocation

In principle, there are three different types of users that can be charged: generators, loads and wheelers. In the end, it is of course the load that pays for the complete costs. Nevertheless, the cost allocation affects the question of using the system efficiently as well as the question of non-discrimination for several reasons:

- A non-uniform ratio of cost allocation among the three user types within one system (or among interconnected systems) creates imbalance between the market partners. Those generators paying less will have advantages on the market in comparison with the others.

  For instance the proportions of costs allocated to generation and load differ considerably in the Scandinavian transmission system, especially since Finland has moved to an almost complete cost allocation towards load Figure 9.1 In general, it is considered sensible to let these ratios converge, but the need for a quick and strict harmonisation is not seen, also in view of the fact that there are other charge elements like taxes that are not harmonised, either.

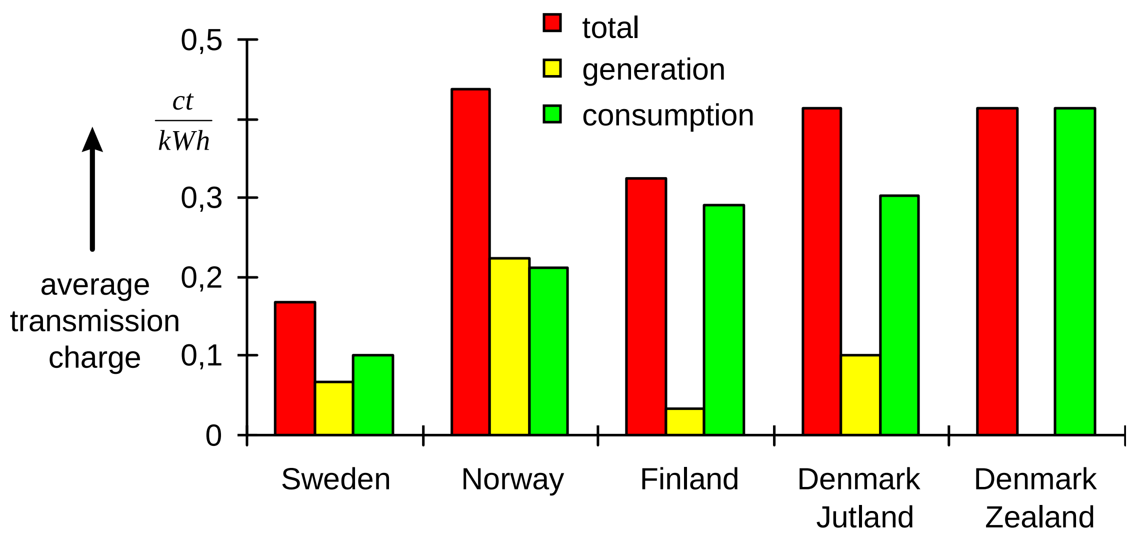


Figure 9.1 Transmission cost allocation in Scandinavian countries (charges calculated from total revenues and amount of power transported), Source: Svenska Kraftnät, April 1999

- A total allocation to the load-side might create imbalances if there are significant in homogeneities between the geographical distribution of generation plants and consumption. The consumers in an area with extensive generation surplus might complain about too high use-of-system charges in their area, caused by the generators that produce power for external consumers.
- Another reason for allocating at least a minor part of costs to generation might be to create a „dummy“ charge element that can, if necessary, be used to include locational price signals towards generators. Of course, this would also be possible if the average of cost allocated to generators were zero, by introducing positive and negative charges, but it is practically easier if their is a general charge element for generators. On the other hand there is no evidence at the moment that locational prices ever had significant impact on the system development until now [1].
- Another aspect of relevance concerns the charging of wheelers. On the one hand multiple charging of energy which is traded several times before leaving the system does not appear to be very cost reflective, on the other hand strong wheeling may increase losses and create congestions, thus leading to additional costs. Therefore, the allocation of at least a minor part of costs to wheelers seems useful especially in those systems heavily affected by transits crossing the system, which should be discussed more detailed in the context of cross-border-transits.

The cost allocation problem in national network tariffs is presently very actual task in EU, particularly related to the newest mechanism for cross-border-trading (CBT).

Present situation regarding the sharing of network operator costs among customers (L-loads, G-generators) in selected European countries is as follow:

	AT	BE	CZ	DE	I	SLO	ES	S
L	83.5%	100%	100%	100%	94-98%	100%	100%	75%
G	16.5%	0	0	0	2-6%	0	0	25%

9.2.4 Reference of Charges

Each charge element can be related either to the electric power or the energy transported, or to an appropriate mixture of these reference quantities. The height of power transported can be defined in various ways, e. g. the individual peak power of a generator or consumer or the power during the system peak period. The energy related charge elements are often distinguished with respect to season (winter/ summer tariffs) or daytime (day/night tariffs).

A reasonable argument for power-related charges is the provision of incentives towards a well-balanced and efficient network utilisation since the investment costs of networks are mainly power-related. On the other hand there are several reasons for introducing energy-related charges or charge-elements:

- Energy-related charges are usually easier to understand, to compare and to deal with.
- Short-term trade is difficult to handle with purely power-related charges, which usually do not contain a duration-dependent element but are calculated on an annual basis. This may lead to the situation that short-term transactions are discriminated. Furthermore, the charging of transactions, which do not take place at the same time on a kW-basis, does not reflect the network costs any more.
- Energy metering – especially with regard to small customers – is easier and cheaper than power metering, which requires additional installation in many cases. Furthermore, power metering is often done only at few specific points in time and, thus, more easy to manipulate than energy metering.

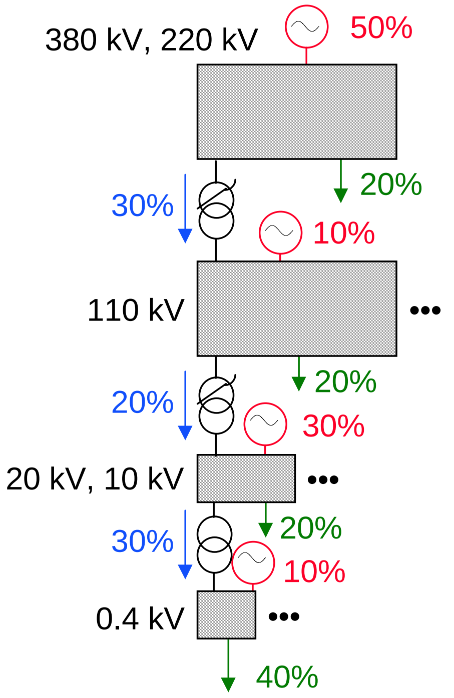
An additional aspect has to be discussed in those systems where a significant share of generation is connected to lower voltage levels: A purely energy-related charge might recoup costs for the transmission network only to a small share in case much of the energy is generated on the distribution levels (net-method). The same applies for power-related methods in case they rely on measured peak demand, at least in case during measurement time the own generation is in operation. This shifts costs from customers with own generation to others without and does not reflect the actual demand to the transmission network in terms of power reserve and ancillary services (example in Figure 9.1). On the other hand a purely load-related charge (gross-method) overestimates the use of the transmission network from the point of view of that distribution system in comparison to others without own generation. The same applies for large industrial customers with on-site-generation. It must be stated here that this problem occurs only in systems with significant generation on the distribution levels or customer-on-site. Otherwise net- and gross-method are equivalent with regard to the share of costs of different customers connected to the same network.

9.2.5 Discussion of different pricing methods

The most significant feature of pricing models is the relation either to commercial transactions of electricity from a source to a sink or to the network access of single network users, independent of the commercial relations among them.

The transaction-based approach requires knowledge of the locations of source and sink for calculating the charges payable for a specific transaction. It is not important which one of the transaction contractors will pay the charges or if they share them. The payment of the charge gives the contractors the right to perform exactly the transaction that the charge has been determined for. When this concept is chosen, network charges can depend in some way on the path between source and sink, for example by incorporating parameters like the geographical distance, the number of network regions affected, or the voltage levels incorporated in the electric path.

In the non-transaction-based approach, on the other hand, the payment of charges gives an individual network user the right to trade with any other market player within the complete range of validity of the tariff system. This requires that the charges cover costs of all voltage levels that the network user potentially accesses, i. e. usually all levels including and above his connection level. It is not possible to take account of a transmission path in this model because the charges are independent of commercial relationships. Instead, the tariffs can be differentiated region-wise or even substation-wise to include locational price signals. Since non-transaction-based charges are not paid „in common" by generators and consumers, a clear definition of charges for each of these types of actors is necessary. The way costs are split between generation and consumption offers an additional degree of freedom in designing the pricing model.



gross-method	net-method
EHV: 20% HV: - MV: - LV: -	EHV: 40% HV: - MV: - LV: -
EHV: 20% HV: 25% MV: - LV: -	EHV: 30% HV: 50% MV: - LV: -
EHV: 20% HV: 25% MV: 33% LV: -	EHV: 12% HV: 20% MV: 40% LV: -
EHV: 40% HV: 50% MV: 66% LV: 100%	EHV: 18% HV: 30% MV: 60% LV: 100%

Figure 9.2 Gross - vs. net-method

There are many general advantages of non-transaction-based pricing with particular respect to non-discrimination and promotion of competition [2]:

- It is much easier to verify non-discriminatory treatment of network users because for this purpose it does not require the existing supply situation to be decomposed into a large number of single transactions, which is not a trivial task.
- Changes of supplier are easier and can be done quicker because they do not affect the network charges.
- The information demand for calculation of the charges is necessarily very low and does not include information on commercial relationships, which makes the calculation simple, practicable and better understandable for all market actors and better satisfies the confidentiality needs, compared to transaction-based models.
- Transaction-based charges which perfectly reflect the cost structure have to be very complex, among others they need to be direction dependent in order to consider the superposition of load flows. Otherwise they are likely to evoke conflicts in individual cases where the physical effect of a transaction is easy to see and is not satisfactorily reflected by the charges. Such examples may also create the suspicion that network operators receive charges for transports that, physically, do not take place at all. Non-transaction-based models do not bear this risk as they are not related to physical (or contractual) flows.
- In a transaction-based model different contract-conglomerations may lead to the same physical load flow but to different amounts of network charges. For example in case a

distance component exists those scenarios with longer contract-paths in average lead to a higher total network charge than those with shorter ones, even though the physical load-flow might be the same. This makes it difficult to estimate the individual transaction charge in advance if a 100-%-cost-recovery is achieved. Again, non-transaction-based models do not bear this problem.

- Power trading on the wholesale level is usually done by compiling purchases and sales to portfolios, not by contracting single source-to-sink transactions. An allocation of sources and sinks would have to be created „artificially“ for the purpose of transaction-based charging, which is not only an additional complexity, but can involve the consequence that traders do not know the sum of due transmission charges before termination of trade for a specific period in time. This is a form of „ex-post“ pricing which can generally be considered adverse to transparency.
- The latter argument is particularly true for anonymous markets like power exchanges. Although transaction-based transmission charging might not be absolutely incompatible with power exchanges (cf. trade with other goods), it will at least impose considerable complexities compared to completely non-transaction-based arrangements.

For these reasons, many countries have chosen non-transaction-based transmission pricing concepts, e.g. UK, the Scandinavian states, Portugal, Austria, the Netherlands, Slovenia, etc.

Nevertheless, there are also advantages of transaction-based pricing, essentially due to the fact that the incorporation of the specific path between source and sink in the calculation of charges makes it easier to reflect the individual use of the system by a transaction [2]:

- The charges for transactions over very short distance could be reduced compared with the average charges, to give incentives for supply from generation located nearby. Similarly, the charges for transactions over very long distance could be higher than average charges to reflect the fact that, at least in simplified models or in statistic average, transmission costs increase with the distance. The objective of this might be „individual“ cost-reflectivity for fairness and for providing signals towards effective transmission system utilisation.
- Surcharges for transactions across congested areas could be introduced in order to give direct incentives to relieve congestion.
- Charge elements for networks which are affected by transits (or loop flows) could be directly included, covering a part of the transiting networks’ costs. This would relieve the tariffs paid by those network users connected to the transit networks, which could be regarded a form of “collective“ cost-reflectivity.

The major pros and cons for both approached are summarised in

Table 9.2 and **Error! Reference source not found.**.

Table 9.1 Price signals expected from transaction- and non-transaction-based systems

	Transaction-based	Non- transaction-based
Loss reduction	Distance dependencies (but usually no direction dependencies!)	Only long term (Locational based pricing)
Sitting of generators	Distance and location dependencies	Allocation of costs to generators (Positive and negative)
Avoid congestions	Additional charges	Difficult (Counter trading, market splitting, locational based pricing)
Charge for wheeling	Easy to implement	Additional element necessary
Efficient network extension	-	-

Table 9.2: Promotion of competition in transaction - and non-transaction-based systems

	Transaction-based	Non- transaction-based
Transparency of charges / non discrimination	Difficult (decomposition in individual transactions)	Easy (only dependent on characteristics of network user)
Prediction and fluctuation of charges	Difficult (dependent on future commercial relations)	Easy
Demand of information	High (each individual transaction)	Lower (each individual network user)
Compatibility with trading systems	Difficult (e.g. energy exchanges)	Very easy
Change of supplier	Changes tariff	Does not affect tariff

The pricing mechanisms can be roughly divided in four categories: Point-to-point, postage stamp, zonal and nodal pricing [1]. In the following their basic ideas are briefly discussed.

9.2.6 Point-to-Point

Typically this method derives charges, which reflect the quantity of the electricity product, the voltage levels involved and the distance the product is carried from the supplier to the consumer. The common link among all distance related methods is that a transaction is charged based on the extent to which specific transmission facilities are used in support of the transaction. The extent of transmission facility use can be established by analysing the transmission system with and without a specific transaction to determine the change in power flow on each transmission facility due to the transaction. The change in power flow, the length or type of facility, and the cost of the impacted facility all affect the transaction charge for use of the system. An example is depicted in Figure 9.3.

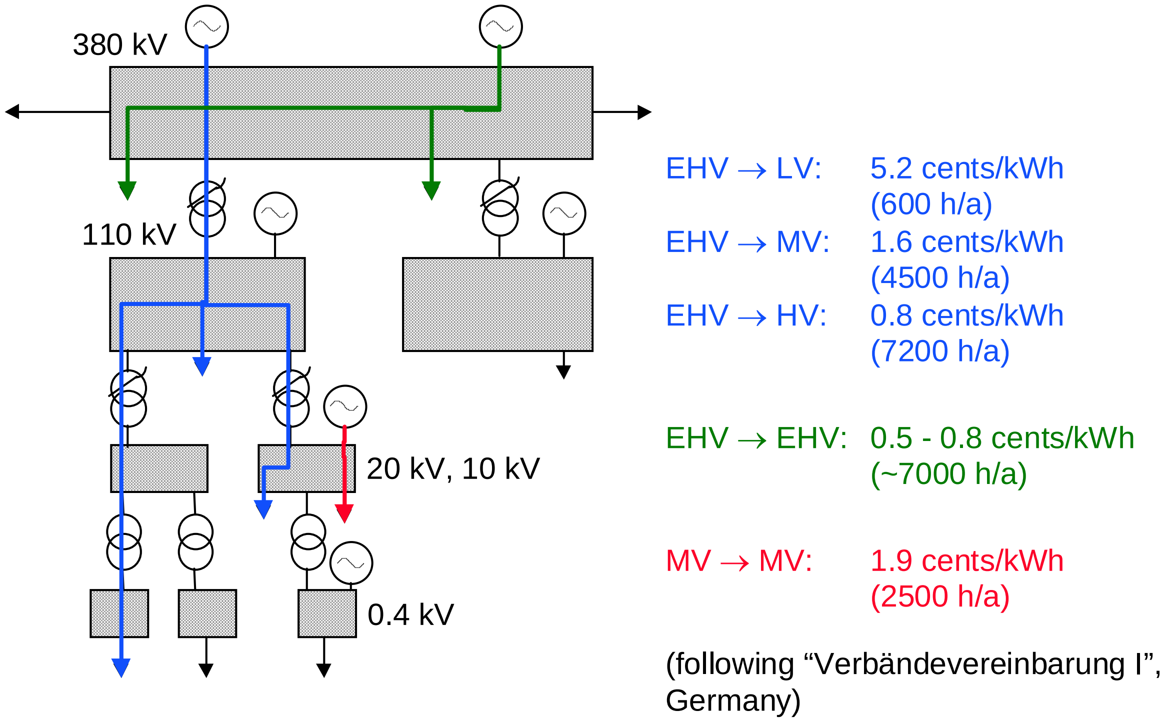


Figure 9.3 Basic scheme of a point-to-point-tariff

9.2.7 Postage Stamp

The so-called postage-stamp-method is a non-transaction based method. In contrary to other point methods postage stamp does not reflect in any way the geographical location of the network user. This means that all of the system infrastructure costs are averaged over a base of customers who use the infrastructure. This can be done separately for each voltage level or sub-system. All users pay the same price for network access irrespective of their geographic location, and the charge is usually based on their peak usage/demand. This reflects the basic concepts behind the design of the transmission system to meet peak capacity requirements. This approach has been widely used throughout the world as the basis for recovery of the embedded costs of the transmission system infrastructure [1].

Uniform, postage stamp methodologies are prevalent throughout the world, particularly in newly unbundled systems. Advantages are simplicity, perceived non-discrimination. Postage stamp methodologies do not influence generation or load location decisions. The example in Figure 9.4 gives some rough price-examples.

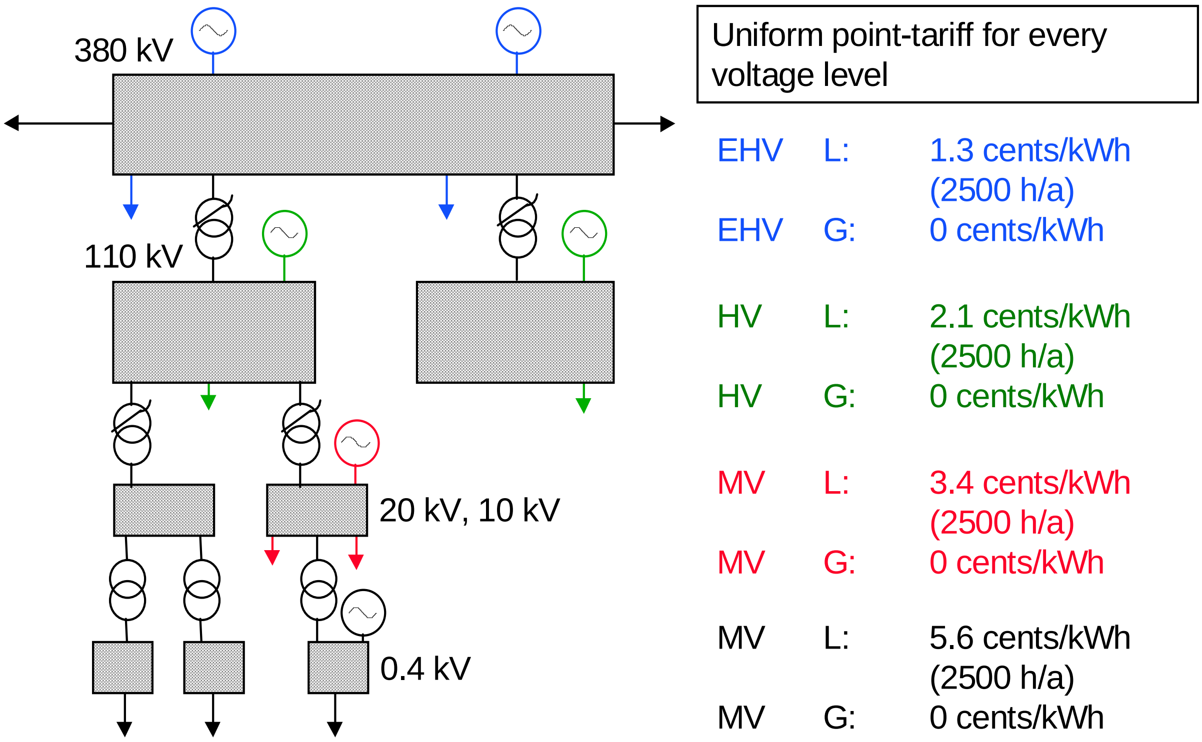


Figure 9.4 Basic scheme of a postage-stamp-tariff

9.2.8 Zone

This non transaction based method attempts to reflect more accurately the true cost of providing service to customers located in different parts on the system. Essentially this involves charging generators more in zones, which are generation-rich, charging load customers more in zones, which are load-rich and vice-versa. Both are usually charged for using the network (-level) they are connected to and all above, reflecting the fact, that the system as a whole is initially and irrevocably designed as an interconnected system. The charge can also include elements, which act as an incentive towards an appropriate system development in the future and, thus, could influence sitting of generation and load.

Zonal pricing is applied successfully in many countries. The zones are often defined according to areas of responsibility (different network owners), furthermore a differentiation between areas with different structure (lack or surplus of generation, rural or urban areas) can be applied. Charges for loads are usually positive and cover 50-100% of the network costs. Generation charges may also be negative as an incentive for generators to settle in high load areas. The scheme depicted in Figure 9.5 is similar to postage stamp.

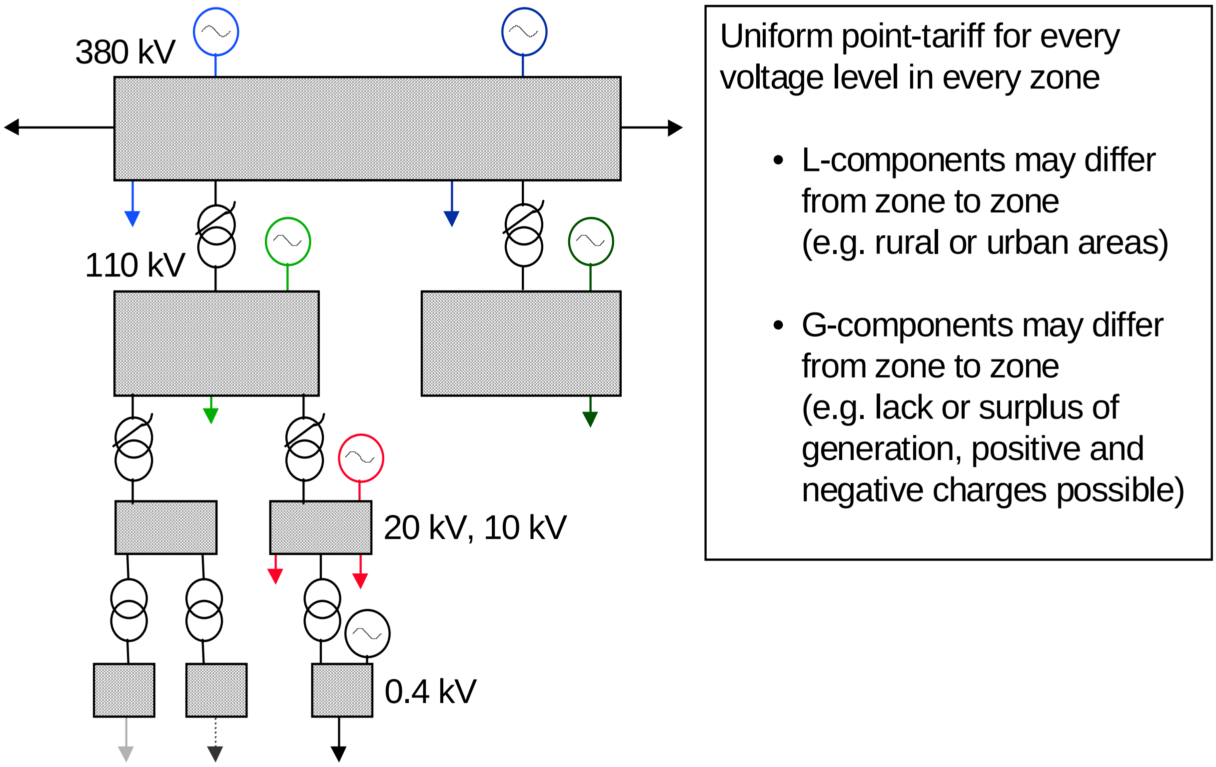
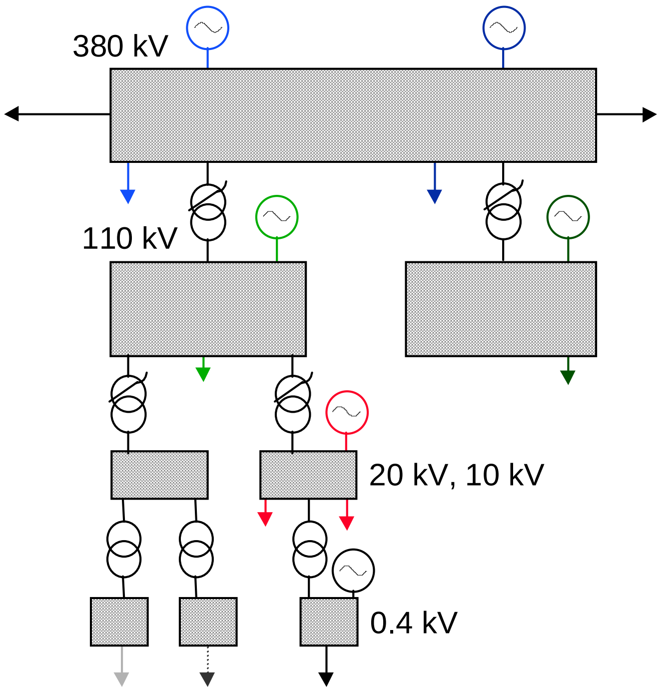


Figure 9.5 Basic scheme of a zonal tariff

9.2.9 Nodal

In theory this concept could be refined to the point that a use-of-system cost could be derived for every node on the system, and an appropriate price for it developed (e.g. nodal loss indices [3]). As a matter of fact no model could be developed yet that is able to do so for all cost elements. Therefore, and for practical purposes, groups of nodes with similar prices are lumped together to form the zones mentioned above.

In both zonal and nodal pricing, many transmission-pricing schemes distinguish between short-term variable costs (e.g., losses and congestion) and long-term costs (i.e., transmission reinforcements). Again the scheme is depicted in Figure 9.6.



Non-uniform point-tariff, different for every node

- L-components may differ depending on location (e.g. rural or urban, close to station or far out), impact on losses, ...
- G-components may differ depending on location (e.g. lack or surplus of generation), impact on losses, ...
- use-of-system- and loss-charge may be based on marginal costs and congestion-costs

Figure 9.6 Basic scheme of a nodal tariff

9.2.10 Pricing methods in selected countries

9.2.10.1 Austria

The Austrian point tariff is uniform for the major part of the country. Charges for use-of-system, containing already several ancillary services, and charges for losses are allocated to the consumer. While the energy-related loss charge applies to the total energy consumption, the use-of-system charge is divided into an energy-related gross component and both energy- and power-related net components. Ancillary services as regards primary and secondary control are charged to the generator as gross components. If energy is designated for export, the loss charge has to be paid in addition by the generator (Table 9.3).

Table 9.3:Main characteristics of the Austrian tariff

Status	• 100% opening by July 2004
Tariff - type	zonal
Cost allocation	• L: use-of-system, losses • G: ancillary services
Components	• Use-of-system (contains voltage control, black-start, operation, congestion management), kWh+kW-basis (kW max. 50%) • Losses, kWh-basis • Ancillary services (frequency control), kWh-basis • Balance power • Metering and network connection
Sharing of costs	Mixed gross/net-method: 60%/40%
Special features	G charged for use-of-system and losses for exports

9.2.10.2 Germany

The current German tariff (Table 9.4) is a G-L-T-type with two areas ("trading hubs"). Within these areas a point tariff is applied, which contains at the moment only an L-component, G is set to zero. The network charge contains use-of-system, losses and ancillary services and is calculated on an annual peak-demand-basis, corrected by "simultaneity factors". It is thus a net-method on kW-basis. The gross- vs. net-discussion is solved by introducing reserve-network-capacity for reduced charge, which may be ordered by consumers with own generation. Within the trading hubs the charge is not uniform for each voltage level but depends on the individual companies real costs. A further differentiation e.g. in urban and rural areas is prepared by some companies on the distribution level.

As Germany decided to open the market at once for all customers it was necessary to develop methods for determination of low-voltage-customer load curves. In order to avoid extensive metering two models were developed which create load profiles based on a standardised set and additional metering.

Table 9.4: Main characteristics of the German tariff

Status	100% opening since April 1998
Tariff-type	• Point-to-point until December 1999 • Point (G-L-T with 2 zones) since December 2000
Cost allocation	• L: 100% • G: 0 • T: 0.25 Pf/kWh (interzonal), 0.125 Pf/kWh (import, export)
Components	• Use-of-system (contains frequency control, voltage control, black-start, operation, losses) • Reserve-power • Metering and network connection
Sharing of costs	• Net-method, corrected by simultaneity-factors, introduction of reserve power • kW- and/or kWh-basis
Special features	• Application of standard load profiles for LV-customers • Reimbursement for co-generation added to use-of system-charge

Most of the German utilities have published their tariff in Internet; an example is depicted in Figure 9.7 up to Figure 9.10.

Charges for use of system

Tapping point in	Annual utilization time < 2500 h/a: Demand rate €/kWa	Annual utilization time < 2500 h/a: Energy rate ct/kWh	≥ 2500 h/a: Demand rate €/kWa	≥ 2500 h/a: Energy rate ct/kWh
Extra high-voltage system	3.11	0.74	17.86	0.15
incl. transformation	8.11	0.74	22.86	0.15
High-voltage system	5.10	1.25	30.10	0.25
incl. transformation	14.10	1.25	39.10	0.25
Medium-voltage system	8.21	1.99	47.96	0.40
incl. transformation	23.21	1.99	62.96	0.40
Low-voltage system	12.16	3.23	70.91	0.88

Charges plus extra cost (currently 0.01 ct/kWh) pursuant to the "Stromeinspeisungsgesetz" (Act Governing Power Generation From Renewable Energy) and turnover tax.

Price sheet 1 Last amended: Feb. 17, 2000 RWE Energie

Figure 9.7 Tariff in Germany Charges for use of the system

Charges for use of reserve system capacity

Tapping point in	Use of reserve capacity: 0 h/a - 200 h/a €/kWa	200 h/a - 400 h/a €/kWa	400 h/a - 600 h/a €/kWa
Extra high-voltage system	7.75	9.30	10.85
High-voltage system	13.00	15.60	18.20
Medium-voltage system	20.75	24.90	29.05
Low-voltage system	37.00	44.40	51.80

Charges plus turnover tax.

For the energy taken up by using this reserve capacity, extra costs (currently 0.01 ct/kWh) will be charged pursuant to the "Stromeinspeisungsgesetz" (Act Governing Power Generation From Renewable Energy).

Price sheet 2 Last amended: Feb. 17, 2000 RWE Energie

Figure 9.8 Tariff in Germany Charges for use of reserve system capacity

Charges for metering of demand and energy

Charge for demand metering (one metering point) at:

1.) *Extra high-voltage level*	377.00 €/month
2.) *High-voltage level*	356.00 €/month
3.) *Medium-voltage level*	157.00 €/month
4.) *Low-voltage level*	120.00 €/month

These charges include the following scope of services:

In general:	Provision of pulse and demand integration period outputs, data transmission, plausibility check, daily provision of the measured data, billing.
In addition for 1),2)	4-quadrant measurement, radio synchronization, cabinet for the equipment.

Charges will be agreed individually for any other scope of services.

Charges plus turnover tax.

Price sheet 3 Last amended: Feb. 17, 2000 RWE Energie

Figure 9.9 Tariff in Germany Charges for metering

Charges for standby energy / supply of emergency power

	Monthly demand rate	*Energy rate*
Standby energy	*15.00 €/kW and month*	*3.07 ct/kWh*
Supply of emergency power	*30.00 €/kW and month*	*6.14 ct/kWh*

Charges plus turnover tax

Price sheet 4 Last amended: Feb. 17, 2000 RWE Energie

Figure 9.10 Tariff in Germany Charges for emergency

9.2.11 Netherlands

The Dutch TSO charges according to a uniform point tariff, consisting of a use-of-system charge including costs of losses and related to peak demand, and two different charges for ancillary services, one of them applied to net energy supplied from generators in the transmission network, the other one applied to the peak demand covered from generators connected to a distribution network. The transport tariff in the distribution network follows a zonal model. The sharing of costs between the networks-levels follows the gross-method, for end-consumers with own generation the net-method is applied (Table 9.5).

One significant feature of the Dutch system is the strict price-regulation by DTe, the Dutch regulator. DTe also introduced annual price-caps for matter of cost-reduction.

Table 9.5: Main characteristics of the Dutch tariff

Status	• 100% opening by January 2004
Tariff-type	• Postage stamp • Zonal in distribution
Cost allocation	• L: 100% of MV/LV, 75% of EHV/HV • G: ≥ 110 kV: 25% EHV/HV cost < 110 kV: 0 • G on-site at end-consumers: ancillary services
Components	• Use-of-system (contains voltage control, black-start, operation, losses, stranded costs), kWh+kW-basis • Ancillary services (frequency control), kWh-basis • Metering and network connection
Sharing of costs	• gross-method between network-levels • net-method for end-consumers with own generation
Special features	• use-of-system charge also for imports • regulated national tariffs by DTe, annual price-caps

9.2.12 Spain

The Spanish point tariff for the wholesale daily market published by the government does not charge generators at all, but allocates all costs to the consumers. The tariff consists of an energy-related and a power-related gross component, both of which vary with regard to time. Time periods are chosen to represent different load factors of the total system, depicted in Figure 9.11.

The tariff components are represented here by average values, and the relevant power is determined through the simultaneity factor [2]. Several additional elements, such as a competition transition charge or incentives for renewables, are included in the access charges. An interesting feature of the Spanish system is the fact that network costs are not based on real costs but on the calculated costs of an ideal reference network model. The sharing of costs is also based on computations carried out on such a model (Table 9.6).

Losses have to be included in the total acquisition bids to the wholesale market according to coefficients published by the system operator. In this comparison, costs of losses are calculated by multiplying the estimated value of loss coefficients with the average energy price [2].

Table 9.6 Main characteristics of the Spanish tariff

Status	• 100% opening by July 2004
Tariff-type	• Postage stamp • Nodal loss-coefficients
Cost allocation	• L: 100% • G: 0 (but uplift on energy price)
Components	• Use-of-system "access charges": - "network costs": 100% of distribution and 20% of transmission costs - "permanent costs": market operation, competition transition charges (CTC), compensation for non peninsular territories - "diversification & security costs": nuclear moratorium, stock & waste nuclear fuel disposal, incentives for cogeneration, renewables & interruptibility discounts kWh+kW-basis with 6 different periods for 5 voltage levels • Ancillary services (frequency control) and losses as uplift on the energy price, kWh-basis • Metering and network connection
Sharing of costs	• Distribution costs (according to an ideal "reference network model"): - LV (< 1 kV) 16.60% - MV (< 36 kV) 50.34% - HV (< 220 kV) 33.06% • kW / kWh-basis: - LV (< 1 kV) 40% / 60% - MV (< 36 kV) 60% / 40% - HV (< 220 kV) 70% / 30% - EHV 80% / 20% • Access-charges: net-method • Permanent, diversification & security costs: kWh or % of total bill
Special features	• Additional use-of-system charge for exports • Additional uplift for constraints and "power guaranty"

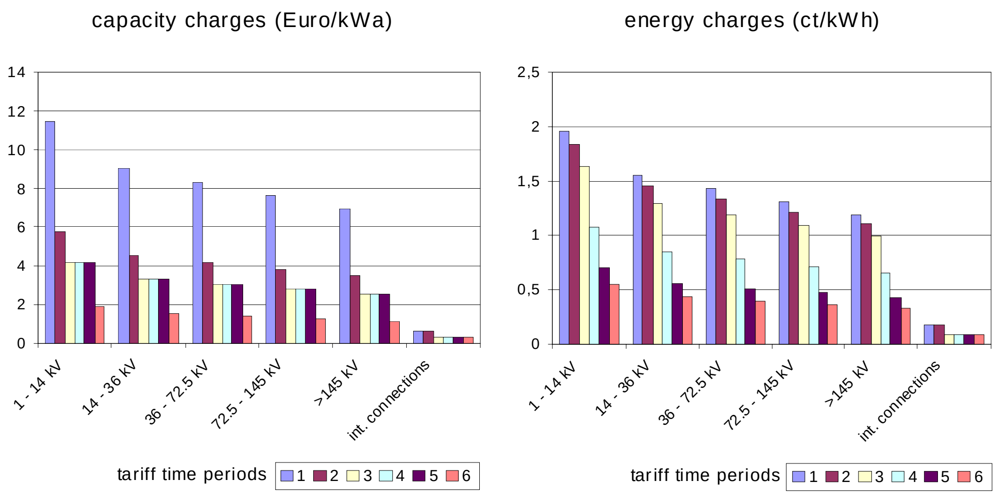


Figure 9.11 Current access charges in Spain (without ancillary services, losses, metering)

9.2.13 Cost calculation scheme

Cost calculation is an essential element when developing transmission prices. One important aspect is the unbundling of activities, which were considered to be a uniform business before. A second aspect results from the fact that the scheme for cost calculation contains elements giving incentives with regard to the development of the system, e.g. having deep or shallow connection cost.

One major precondition for the calculation of network cost is the decomposition of a company's total cost into network activities and other activities. Other activities, e.g. generation, retail, sales, gas supply, water supply, telecommunications or technical consulting should be separated by individual income statements and individual cost calculation.

The network activities again have to be broken down into partial network services in order to allow calculating individual cost for using only part of the system (e.g. only transmission and ancillary services). For practical purpose this should only be done up to a certain limit which can be derived from the respective rules describing the network pricing scheme. Generally it can be stated, that as many separate partial services have to be defined as separate prices exist. Most commonly used are transmission, distribution (one per voltage level), transformation (one per voltage step), and ancillary services (one per position defined as separate service). Additional services are those not included in the general pricing scheme because they are assigned to individual network users following the causation principle, like individual connection cost.

As in Kosovo as well in Albania these rules are still to be developed this investigation should use a scheme with as many separate services as necessary in order to compare the different pricing models. It is suggested here to use scheme in Table 9.7.

Further intermediate levels may be defined if necessary. It is important to stress that regional differentiations other than company property should only be made if they appear logical from technical, economic and organisational point of view, e.g. in case a separate business area exists within a company which is in charge of running a part of the distribution system significantly differing from the remaining network in its structure.

For each individual partial network service a separate cost calculation similar to the example in Annex 3 should be carried out.

Many of the cost terms might be taken directly from the income statements if they are referred to separately for the specific partial network services. Cost terms addressing several partial services (e.g. maintenance crews in charge of more than one distribution/transformation level) should be split up using comprehensible allocation keys, which probably have to be roughly estimated in the first step.

The example in Annex 3 reflects the cost terms according to German regulations. They should first be adopted to the Kosovian and Albanian tax and accounting system.

9.2.14 Accounting vs. calculatory depreciation

Depreciation is one major cost element of the total network cost. Accounting depreciation is part of a company's income statement and, thus, determined by commercial and tax laws. Usually declining balance method is applied in the first years leading to rather high depreciation values at the beginning and low values at the end of the depreciation period.

The depreciation periods themselves are usually fixed according to type of asset and tend to be significantly shorter than the expected lifetime. In calculatory depreciation the straight-line method in combination with extended periods reflecting better the expected lifetime leads to constant depreciation values over a longer period Figure 9.12.

Table 9.7 Suggestion for splitting up the whole system into partial network services

Service	Technical sub-system	Regional differentiation
Transmission	380- and 220-kV-lines and 380/220-kV-transformation	No
1st transformation	380/110-kV-transformation and 220/110-kV-transformation	No
1st distribution	110-kV-lines	Preferably no, otherwise according to technical areas and company property
2nd transformation	110/20-kV-transformation or 110/10-kV-transformation	Same as 1st distribution
2nd distribution	20-kV-lines or 10-kV-lines	According to technical areas and company property
3rd transformation	20/0.4-kV-transformation or 10/0.4-kV-transformation	Same as 2nd distribution
3rd distribution	0.4-kV-lines or 0.4-kV-lines	Same as 2nd distribution
Ancillary services	Further differentiation still to be analysed	No

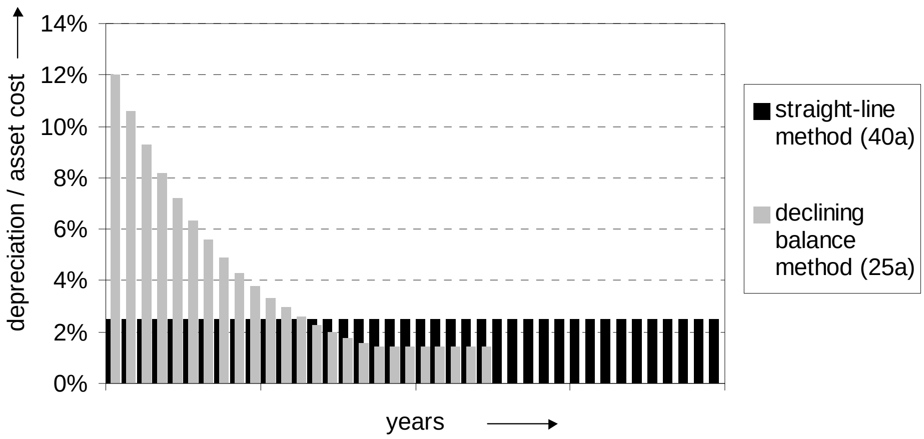


Figure 9.12 Example for depreciation values with straight-line method over 40 years and declining balance method over 25 years

9.2.15 Current market value vs. historical cost

A second question to be discussed is whether historical cost concept or current market value concept should be applied. The current market value of an asset is usually higher and thus helps recovering replacement cost in order to ensure sustainable development.

In [1] it is suggested to apply the historical cost concept (HC) for the calculatory share of assets financed by outside capital, and current market value concept (CMV) for the share financed by equity capital. By this means inflation is automatically integrated in depreciation, at least in case the current market values increases accordingly (Equation 1).

$$\text{calculatory depriciation} = \left(\sum_{\text{all types of components}} \text{total asset value (HC)}_{\text{type,i}} / \text{operating lifetime}_{\text{type,i}} \right) \cdot (1 - \text{ECQ}) + \left(\sum_{\text{all types of components}} \text{total asset value (CMV)}_{\text{type,i}} / \text{operating lifetime}_{\text{type,i}} \right) \cdot (\text{ECQ})$$

Equation 1: Calculation of depreciation depending on the equity capital quota (EQC)

As Equation 1 shows, depreciation and consequently network cost will decrease with decreasing EQC.

9.2.16 Calculatory interest for equity capital

The return on equity capital is first oriented on the return on other investments with comparable duration of capital tie-up and comparable risk. Fixed interest security can be used as a basis and then increased by an additional risk margin. The impact of inflation on sustainable development may be covered by using current market values for calculating depreciation for those assets financed by equity capital. In that case the return on fixed interest security has to be corrected by the inflation rate, thus using real instead of nominal interest rate. The calculation of return on equity requires first the calculation of the necessary operating equity capital itself. The total scheme is shown in Table 9.8. Otherwise inflation should be included in the calculation.

The additional risk margin is not fixed but should be approved by a regulator or other bodies. In the Netherlands this value is set to 7.4% by the regulator. In Germany there are examples using values between 1% and 3%.

Table 9.8 Scheme for calculating return on equity

	position	amount
	necessary operating capital	0,00
	calculatory residual value of fixed and intangible assets (HC)	
	balance sheet value of financial investments	
	balance sheet value of floating assets	
-	capital items deducted from total	0,00
	liability reserves	
	advanced payments and deposits aleady received	
	non-interest-bearing liabilities	
	building subsidies already received	
	other non interest-bearing liabilities	
-	outside capital	0,00
	liabilities to financial institutions	
	interest-bearing liabilities to affiliated companies	
	other interest-bearing liabilities	
=	necessary operating equity capital	0,00
*	return on equity capital	0%
	interest rate of fixed interest security (10-years-average)	
	additional risk margin	
=	calculatory return on equity capital	0,00

9.2.17 Allocation keys for general cost sections

A number of (internal) services are provided for more than just one of the partial network services mentioned above. This requires the application of allocation keys if no better system – like for instance consequent internal clearing – exists. There is no general rule for allocation keys apart from that they should be as cost-reflective as possible. A possible approach for allocation key can be found in Table 9.9. However, it has to be mentioned here that those keys, even if simple to apply, should be dealt with care because they allow to shift cost from one network service to another or even to or from services within the company but not related to network activities ("horizontal subsidies“), which may lead to market-distortion.

Table 9.9 Examples for allocation keys

Service	Possible keys
Human resources	• Number of heads
Board	• kWh • Assets value
Vehicles pool	• Heads • Maintenance crews
Accountancy	• Asset value • Turnover
Clearing	• kWh • Number of customers
Maintenance	• Heads • Estimated working hours + material • Length of lines (for allocation to different network areas with same or similar voltage)
Cable construction	• Length of line constructed

9.2.18 Network cost: Examples from German companies

A major assumption to be made when calculating network cost is 100-%-opening to the market. This means that network cost are calculated as if all customers were eligible (many of EU countries already full opened its electricity market; all open EU electricity market is determined for July 2007). This allows calculating non-discriminatory network cost for all users. Total cost for non-eligible customers can then be calculated by adding the energy price.

This chapter is intended as orientation for preparing own network tariffs quantifies network cost to be found in Germany. The following figures are not collected for means of benchmarking the individual companies; some of them may implicitly contain elements, which have to be negotiated for other companies separately. An example of such an element is an additional risk margin for serving low-voltage (LV) customers without ¼-h-metering.

The following elements are not included in the figures below:

- Concession fee: 0.5..2.5 ct/kWh (applicable to customers below 30 kW / 30000 kWh/a, larger customers have reduced value or are free of charge above a certain limit)
- Additional risk margin for serving LV customers without ¼-h-metering (partly not included): ~0.2 ct/kWh
- Additional fee to promote cogeneration according to the respective law: ~0.25 ct/kWh

They sum up to 0.95..2.95 ct/kWh plus taxes and thus increase the LV-customers-prices significantly. Generally it can be said that calculation of network cost in Germany is not always carried out by purely commercial calculations but also by considering the company’s corporate policy. For example the network operators are free to not include all possible elements into their calculation if they want to have low prices for other reasons.

Figure 9.13 gives an overview of the use-of-system charges. They are calculated for different voltage levels and different customer types, the significant characteristics are peak demand and annual utilisation. The exact numbers and values are listed in Annex 3. All values already include turnover taxes (in Germany: 16%). The LV-charges are applicable to customers without ¼-h-metering.

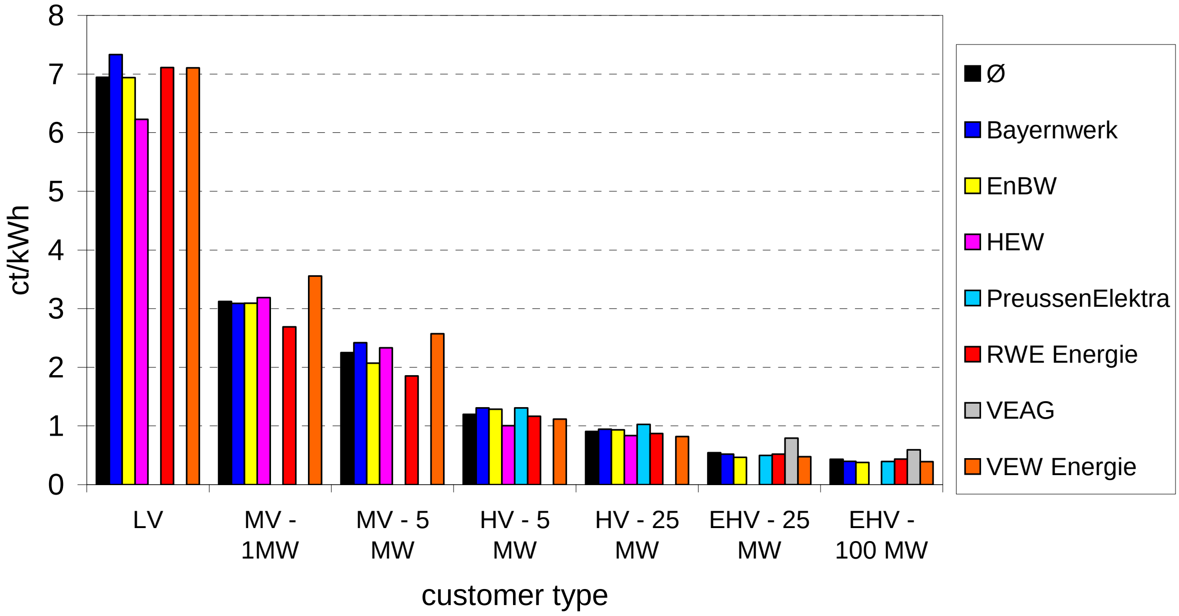


Figure 9.13 Use-of-system charge (incl. turnover taxes)

The other charge elements can be summed up as additional services provided by the network operator. They comprise metering, reactive power, network capacity for loss of auto-production, emergency power and balance power. They are not directly to be added to the network charges for several reasons:

- Metering is required for every customer.
- Reactive power should normally be not required above the limits that are free of charge, large amounts are usually negotiated Figure 9.14
- Network capacity for loss of auto-production is only needed in case of customers who need backup from the network-side for on-site-generation, which might drop out Figure 9.15
- Emergency reserve should only be needed in exceptional casesFigure 9.16
- Balance power is required in case balancing-sphere supervisor's over- or under-estimate the sum of their customers and, thus, depends on the accuracy of the respective load forecast Figure 9.17

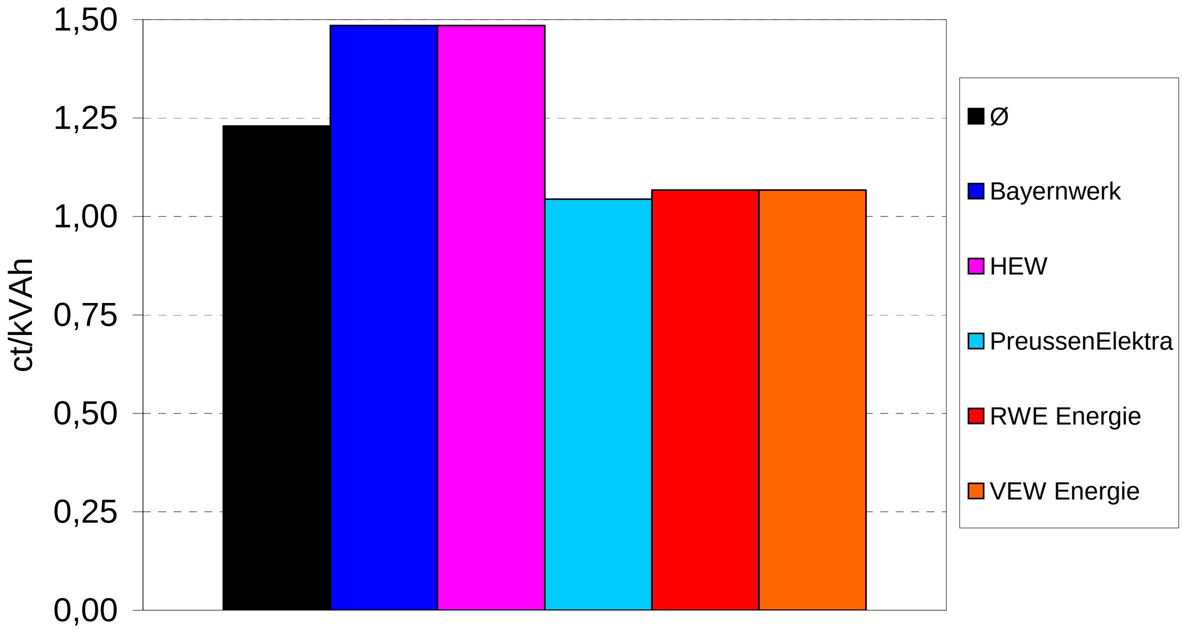


Figure 9.14 Reactive power charge (incl. turnover taxes)

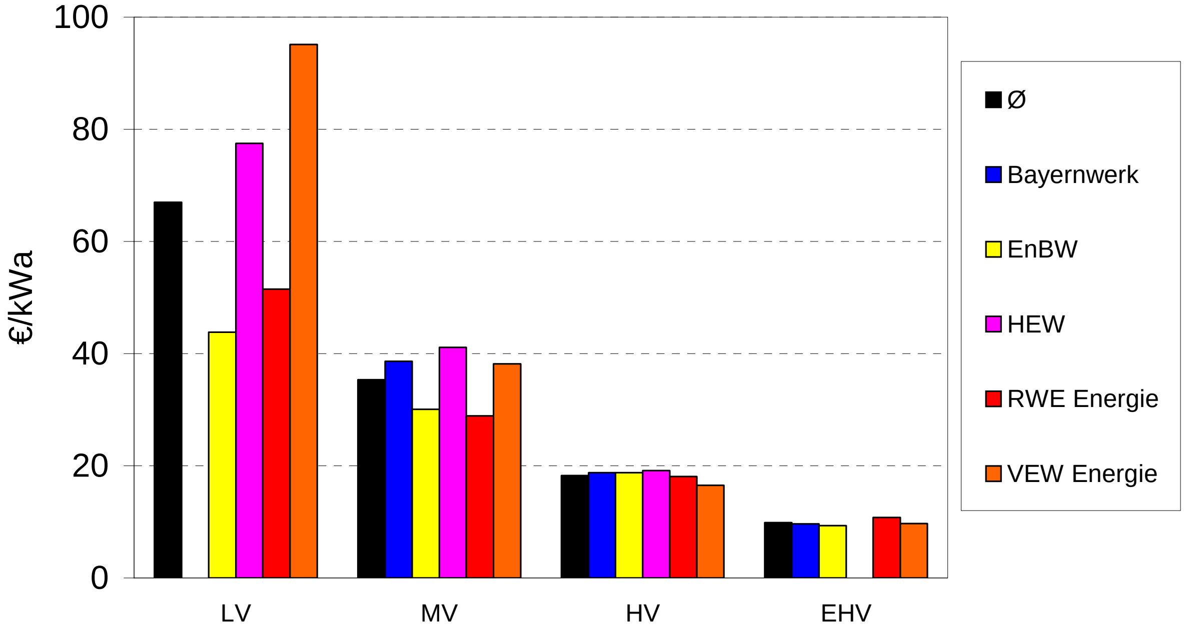


Figure 9.15 Charge for network capacity for loss of auto-production (200 h/a – 400 h/a, incl. turnover taxes)

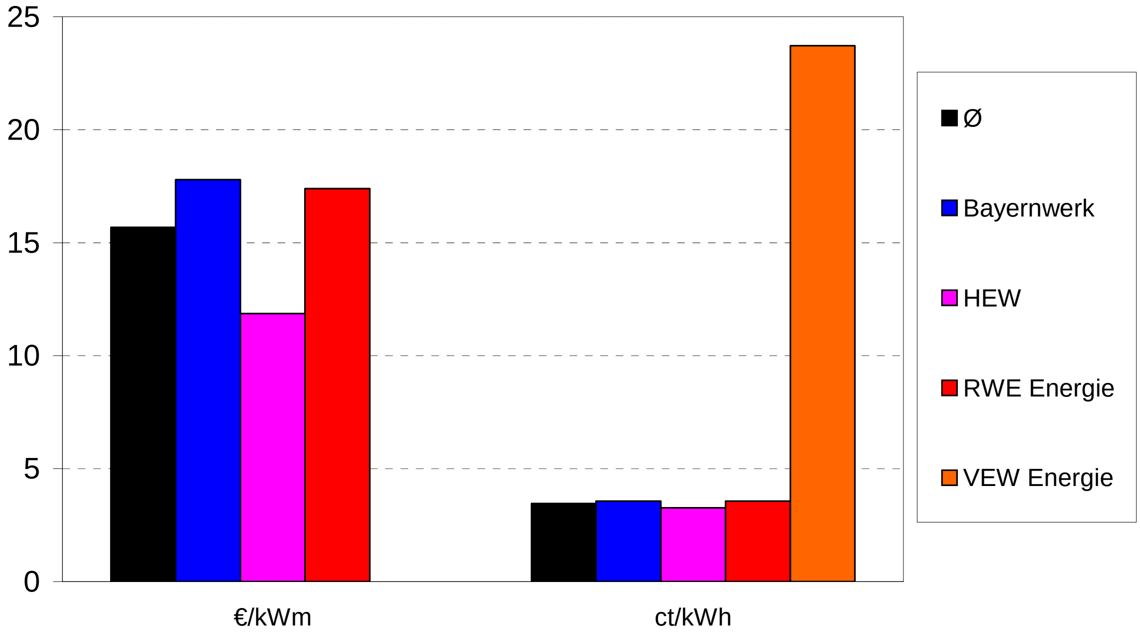


Figure 9.16 Charge for emergency reserve (incl. turnover taxes)

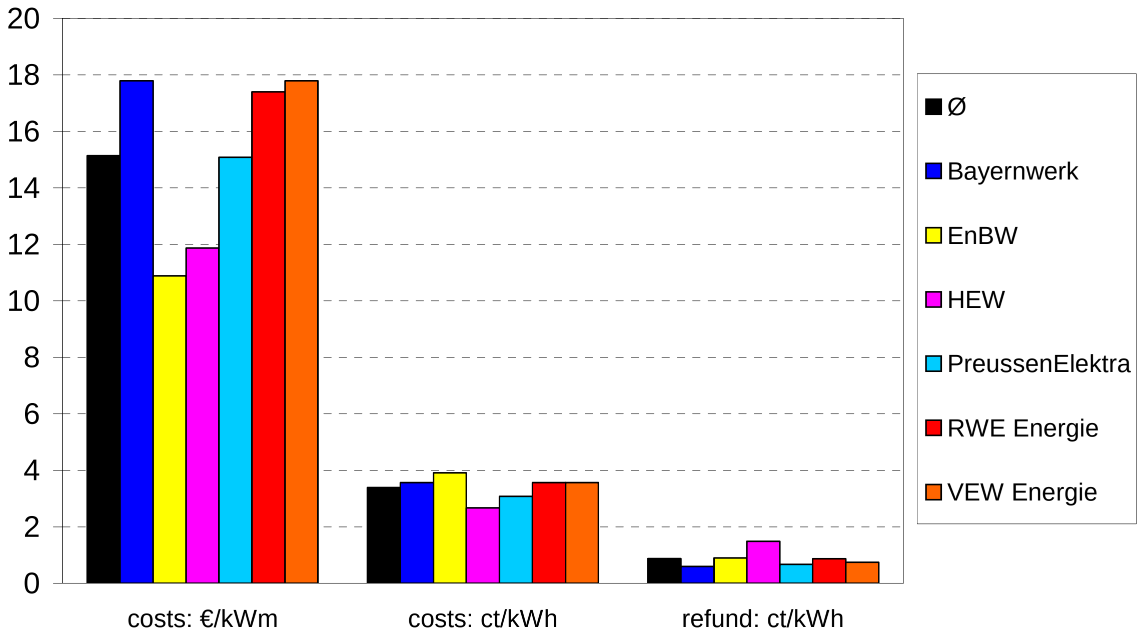


Figure 9.17 Charge for balance power (incl. turnover taxes)

9.2.19 Cross-border tariffs and congestion management

Cross-border trade (CBT) and congestion management are in the focus of the discussion of the European Commission, the national regulators, the ETSO and other associations in last 5 years. The reason is a strong impact on the security of the whole system's operation as well as on international trading. ETSO has prepared first proposals on both items that were discussed on the Florence meeting in March 2000. There are several documents available prepared by ETSO which describe the proposals in detail and contain up-to-date information e.g. on net transfer capacities.

After introducing CBT Mechanism 2003 and CBT Mechanism 2004 (presently used in SEE Region), ETSO launched CBT Mechanism 2005.

Congestion management rule is also in actual discussion in Europe.

9.2.19.1 Cross-border tariffs

It is mostly agreed by the parties involved that two cost terms should be covered by cross-border tariffs, which are additional losses caused by international power exchanges as well as necessary investments in the interconnected system in order to improve its transfer capacity. The discussion focuses on the questions

- how to identify additional costs,
- how to collect the fees, and
- how to redistribute the sum of collected fees to individual TSOs.

The proposal of ETSO suggests establishing inter-TSO-payments to compensate the costs of physical flows (transits and loop-flows). In the first approach CBT 2003 it was proposed to set up a European export stamp paid by generators with a sink outside their country, which is the same all over Europe. A first simplified approach was applied in a transitional period of 1 year. The following steps can briefly describe the method:

- Identification of costs related to cross-border exchanges (identification of the „Horizontal Network“, calculation of full costs including losses, identification of the „international“ part of it)
- Calculation of a „European Stamp“ by dividing the costs identified before by the measured (or estimated in the first step) cross-border exchanges (in MWh)
- Collection of the export fee from the exporting bodies by each TSO in his area, and
- Redistribution of the total sum to the TSOs on basis of hourly measured flows of energy on the tie-lines.

Several associations such as ETSO and Eurelectric but also the regulators recommend to rapidly harmonising the split of transmission charges between G and L. This task is still ongoing.

The CBT mechanism 2005 which is presently active in Europe will be in more detail described in next chapter considering impact of studied interconnection on both power systems Kosovo and Albania, respectively.

9.2.20 Conclusion and guidelines how to develop a Transmission tariff for Kosovo and Albania

Transmission tariff is a part of network tariffs. So, transmission tariffs can be defined as fees for the use of the network, including energy-related fees, capacity-related fees, and fixed fees designed to cover metering and billing expenses.

Development of tariff can be realized in following steps:

1. Step **(Technical and economical system database)**

First step to develop a model requires the preparation of detailed database of technical and economic parameters for the KEK and KESH electric power system. Network data should be prepare in detail considering book values for each network element that is base for annual cost calculation.

It is of great importance for the development of the selected method to set priorities regarding the objectives and requirements to be achieved using the selected method.

The "postage-stamp-method" is quite uniform method that is prevalent throughout the world, particularly in Europe. This is certainly method we suggest to use in Kosovo and Albanian system. Figure 9.18 presents a framework of activities considering postage stamp method approach.

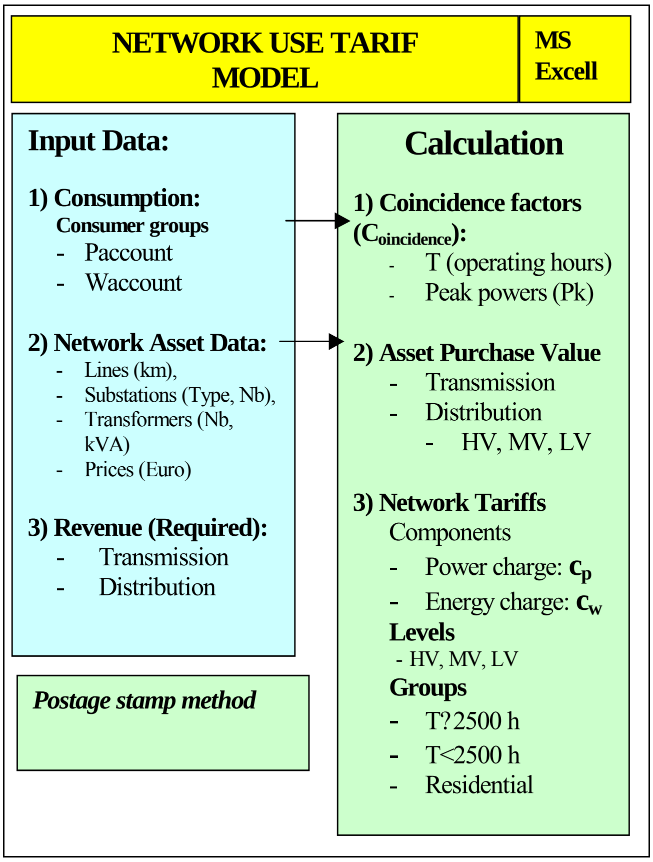


Figure 9.18 Proposed model for Network tariff /R. 10/

2. Step (Basic features of selected method)

The Postage Stamp Method is proposed related to three different voltage levels (Fig. 20):

- High voltage (HV)
- Medium voltage (MV)
- Low voltage (LV)

That means there are unique tariffs at each voltage level independent from the transport distance.

Furthermore, individual different tariffs for three groups of users should be established:

- Users without measurement of demand at the low voltage level (residential)
- Users with an annual utilisation time of less than 2500 hours
- Users with an annual utilisation time of more than 2500 hours.

Cost allocation between L (loads) and G (generators) we suggest in line with recently suggestions of ETSO on Guidelines on Transmission Tariffication in EU.

Finally, the tariffs are split into a

- Energy charge and
- Demand charge.

The proposed pricing system takes into consideration the usual main requirements for a tariff calculation:

- Reflecting the different components of the costs (power or energy related)
- Considering the causation principle (customer with different utilisation hours and at different voltage level)
- Promotion of energy saving (small customers and customers with low utilisation hours have to pay a higher energy charge but a lower demand charge)
- Uncomplicated calculation system.

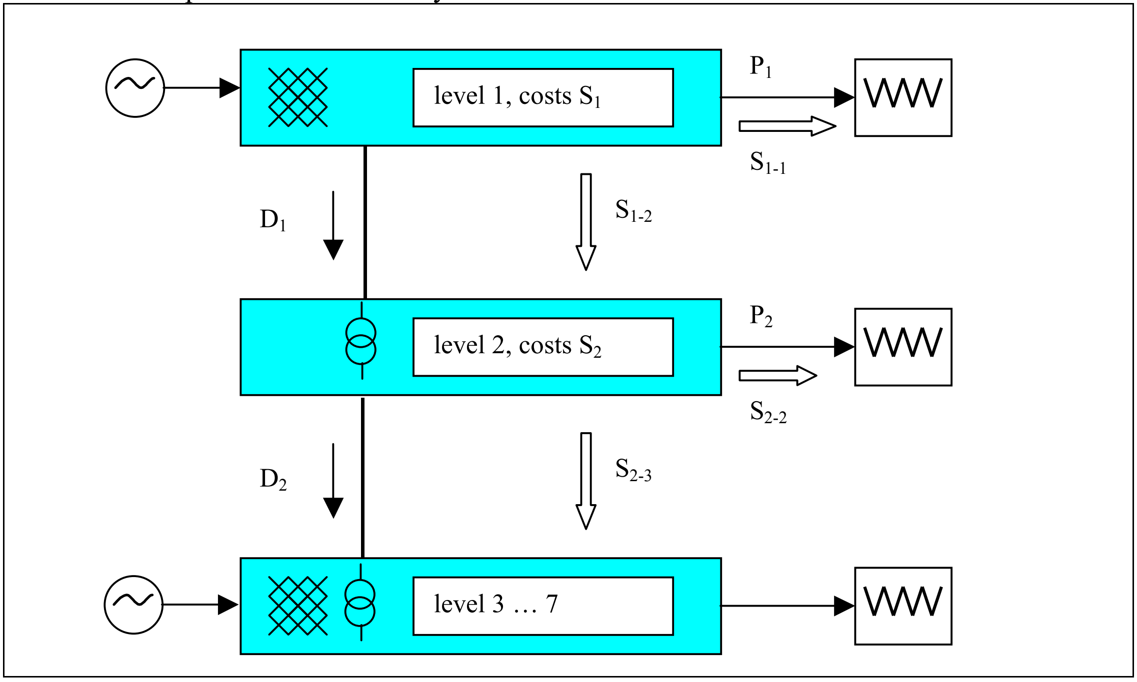


Figure 9.19 Model for cost allocation between voltage levels

Mathematical model for cost allocation between voltage levels will be considered as follow:

Gross method approach

$$S_{1-1} = S_1 \cdot \frac{P_1}{P_1 + P_2 + \ldots + P_7}$$

$$S_{1-2} = S_1 \cdot \frac{P_2 + \ldots + P_7}{P_1 + P_2 + \ldots + P_7}$$

$$S_{2-2} = \left(S_2 + S_{1-2}\right) \cdot \frac{P_2}{P_2 + P_3 + \ldots + P_7}$$

$$S_{2-3} = \left(S_2 + S_{1-2}\right) \cdot \frac{P_3 + \ldots + P_7}{P_2 + P_3 + \ldots + P_7}$$

...

The asset data at the different voltage levels are necessary to assign required revenue of transmission and distribution companies as network costs to specific voltage level.

From the equations (gross approach) for cost calculation between voltage levels it is obvious that customers from lower levels have to cover some portion for the costs at the higher levels.

Mathematically, it is possible to describe as follow:

$$c_{HV} = c_{HV}^{neto}$$

$$c_{MV} = c_{MV}^{neto} + c_{HV}^{neto} \qquad (9.1)$$

$$c_{LV} = c_{LV}^{neto} + c_{MV} = c_{LV}^{neto} + c_{MV}^{neto} + c_{HV}^{neto}$$

$$P_i^{Account} = \sum_k P_{i,k}^{Account}; \qquad W_i^{Account} = \sum_k W_{i,k}^{Account} \qquad (9.2)$$

For HV level at the certain user group i it is as follow:

$$S_{HVi} = c_{P_{HVi}} \bullet (P_{HVi}^{Acco.} + P_{MVi}^{Acco.} + P_{LVi}^{Acco.}) + c_{W_{HVi}} \bullet (W_{HVi}^{Acco.} + W_{MVi}^{Acco.} + W_{LV}^{Acco.}) \qquad (9.3)$$

Accounted demand and energy are known data for any user group and the cost, which have to be recovered are easy to calculate.

3. Step (Calculation of annual costs)

Annual costs for transmission and distribution should be calculated based on asset data of companies. Basic data of assets are available at the three different voltage levels. The annuity factor could be calculated assuming 40 years of life cycle time for the equipment and an interest rate of 4.5 %. These two assumptions result into a very low annuity factor of about 5.4 %.

The resulting annual capital costs considered in the tariff calculation is relatively low. But, more commonly used in many other countries are interest rates of 8 - 10 % and commercial life cycle times of 30 years for transmission and distribution systems.

The latter assumptions would yield annuity factors in the range of 9 to 11% and therefore almost double the annual capital costs. For the expert judgement it is common to use a value of 10% for annual costs.

4. Step (Cost sharing by voltage level)

Cost sharing by voltage level is just explained and suggested to use so-called Gross Method. This is acceptable under the stated condition that generation at the medium and low voltage level is insignificant, what is a fact in both systems (Kosovo and Albania).

If however generation at these levels increases, the costs for the high voltage level would be calculated too high. Considering that in both systems (KEK and KESH) the generation connected at lower levels are insignificant it is suggested to use Gross Method for cost sharing between voltage levels.

5. Step (Calculation of energy and demand charge)

Energy charges and demand charges could be calculated with

- a more "cost reflecting approach" (energy related costs and power related costs are charged as incurred - resulting in a relatively high connection charge) or
- a more "market oriented approach" (defining a certain value for one of the two charges and calculating the other one according to the principle of total cost covering).

We propose a more "market oriented approach". On each voltage level a value for the energy charge (connection charge) is defined. The demand charge is calculated on the basis of the difference between the total annual costs and the annual income earned from energy charge.

Principle for cost sharing between energy and demand (power)

Considering to the fact that energy losses depends of transmitted energy and that customer, particularly connected at the LV level better understand energy than demand it is reasonable to set up two tariffs depending of energy consumption as well as connected power:

1. Cost for connected power $c_{p,}$ and
2. Cost for consumed electricity c_W

Customer k has to pay following costs for electricity transmission ck:

$$c_k = c_P \bullet P_k + c_W \bullet W_k \tag{9.4}$$

Simplified we can write that total cost is:

$$S = \sum_k c_p = c_p \bullet P_{Account} + c_W \bullet W \tag{9.5}$$

Demand and energy are known costs for network, which have to be recovered by customers.

The annual income from users without measurement of demand at the low voltage level and users with an annual utilisation time below 2500 hours, is structured as follows:

- 60 % from energy charge and
- 40 % from demand charge.

This tariff structure supports energy saving.

The annual charge for users with an annual utilisation time above 2500 hours is split into some 30 % energy charge and some 70 % demand charge. This tariff structure gives the customer a strong incentive to estimate very precisely his peak load and to try to stay below his contracted connection. The tariff thus supports a flattening of the load curve.

6. Step (Cost sharing by user groups)

The shares could be calculated based on the peak load structure. An approach in above text is demonstrated in sufficient detail. Figure 9.20 depict annual utilisation time for users groups and suggested criterion for users group selection.

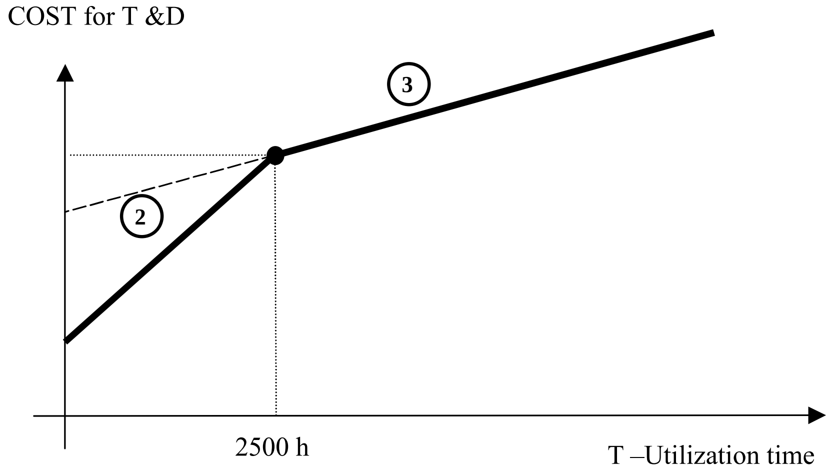


Figure 9.20 Suggested breakeven for users groups

7. Step (Complete Method of Calculation)

1. A detailed data base (economic data, structure of electricity consumption, commercial data all data structured by utilities and voltage levels, etc.)
2. Cost calculation schemes
3. Tariff calculation schemes
4. Transformation schemes to prepare diagrams based on calculated figures.

The tool, which can provides the possibility to carry out sensitivity analyses, to compare results with the tariff structure of foreign companies, to update and to change the tariff structure in line with new developments as they occur, e. g. additional investments in the transmission and distribution systems, could be prepare in simple Excel framework.

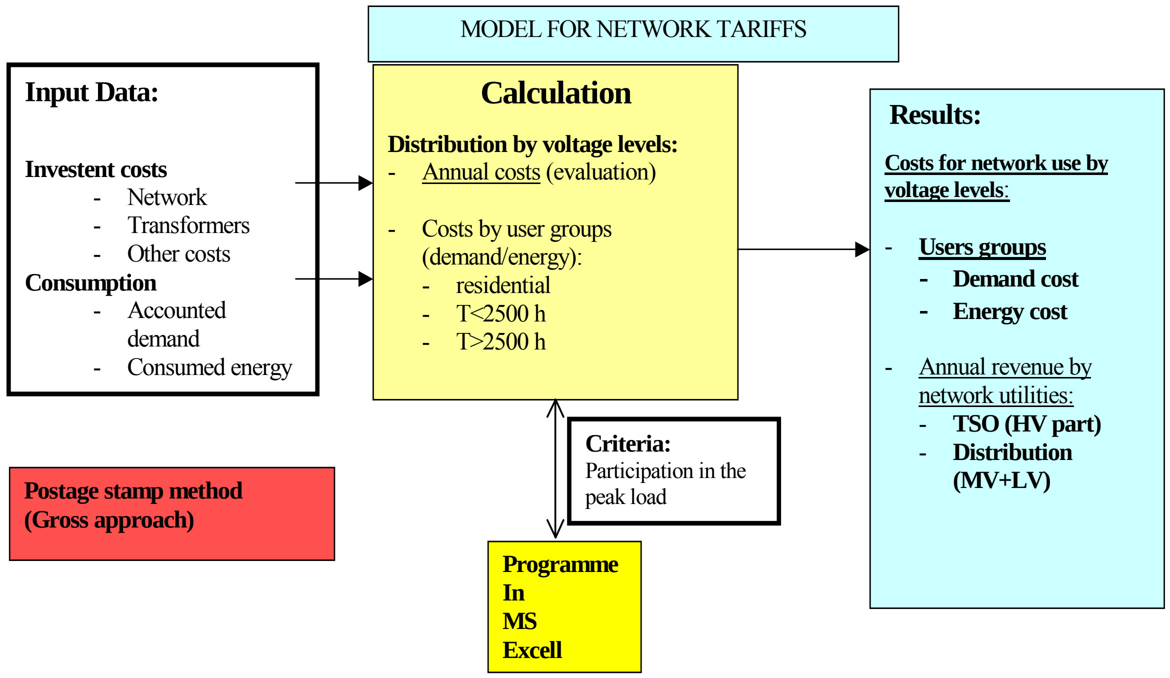


Figure 9.21 Outline of network tariff method approach

10 Development of Cross-Border Trade and CM rule

10.1 Introduction

The organization of cross-border transmission is considered a key issue for the implementation of EU Internal Electricity Market (IEM) in Europe. The creation of a real electricity market is promoted through an intensification of trade in electricity, which is currently considered underdeveloped compared with other sectors of the economy.

The first objective for Cross Border Trade (CBT) mechanism is to facilitate the development of an efficient internal market for electricity. Free trade in electricity should benefit all countries involved.

The second objective is to compensate TSOs fairly for their costs incurred due to cross-border trade.

The third objective for future network tariffs is to provide location signals that contribute to the development of an efficient European transmission network.

Flows owing to CBT can be transits, which are completely unrelated to domestic users, or exports and imports. It is widely accepted that TSOs hosting transits should be compensated for costs or benefits so incurred by the TSOs where the flows start or finish.

Ideal principles of a "fair" application of transmission tariffs in a multinational CBT contexts can be summarized as:

- **non-interference:** locational differences between access tariffs must not interfere with the incentives to operative efficiency provided by marginal prices;
- **proportionality to benefits:** Costs should be allocated proportionally to benefits, measured by the electrical use of the lines;
- **Ramsey pricing:** tariffs should be function of *willingness to pay*, inversely proportional to the elasticity to payment. Therefore, consumers should pay the greatest share.

Other principles are:

- locational signals: applied to energy prices or transmission tariffs;
- avoiding transaction-based tariffs;
- avoiding tariff pancaking.

EU Directives

The EU directives indicate that fair, cost-reflective, transparent and directly applicable rules, should be introduced with regard to cross-border tarification and the allocation of available interconnection capacities, in order to ensure effective access to transmission systems for the purpose of cross-border transactions.

On June 26th 2003 Parliament and European Council approved:

- a new directive on electricity (2003/54/EC)
- a regulation "*on conditions for access to the network for cross-border exchanges in electricity*" (1228/2003)

Aim of the new **CBT regulation** is (art.1): "*enhancing competition within the internal electricity market, taking into account the specificities of national and regional markets. This will involve:*

- the establishment of a compensation mechanism for cross border flows of electricity

- the setting of harmonised principles on:
  - cross-border transmission charges and
  - the allocation of available capacities of interconnections between national transmission systems."

CBT inside the IEM: Florence forum

The **Electricity Regulatory Forum** was set up in 1998 by EC in order to gather stakeholders to discuss the way ahead for the creation of a EU Internal Electricity Market. The trend is towards adopting the concept of the "single system paradigm" so that political borders will not matter in the design of the rules of functioning of the IEM. One of the key orientations that have been adopted for CBT is the compliance with the laws of physics and the maintenance of sound criteria for security of supply.

The Florence forum is attended by regulatory authorities of member states, European commission, TSOs, traders, consumers, producers, etc.

To create a platform for discussion with the purpose of achieving an efficient Internal Electricity Market (IEM) the European Commission, in 1998, initiated the creation of the European Regulatory Forum for electricity, meeting approximately twice a year in Florence, Italy.

The main regulatory questions within the context of the IEM are:

1. **Cross-border tarification:** How much should be charged for the use of the network to the diverse market agents who can buy and sell anywhere within the IEM? Who pays for network losses?
2. **Network tariff harmonization:** In the context of a regional competitive market, can the tariffs in the different countries be entirely left to subsidiarity or some level of harmonization should be required?
3. **Congestion management:** How the priorities in network use are established when the transactions of the agents in the market are not compatible with the existence of physical network constraints?
4. **Transmission network investment:** Who is responsible for upgrading the network when needed and who pays for it?

While at the beginning of this so-called "Florence process" the financial conditions of cross-border transmission access have been given most attention, technical issues like capacity allocation, congestion management and information exchange are currently gaining more importance. In the 10 editions until now of the Florenc forum the most discussed subjects were:

- congestion management in cross-border transactions
- cross border tarification (how to compensate transits and losses)
- how to implement sound short and long term locational signals

CBT and national transmission tariffs

National transmission tariffs are primarily designed to recover domestic transmission costs. However in a common European electricity market national tariffs cannot be treated completely independently, but must meet a number of basic requirements as follows.

- Transmission tariffs shall consist of input and exit charges (G and L) only.
- Tariffs should be independent of the commercial transactions.
- There shall be no extra tariffs for import, export or transit.

A consequence of the previous principle is that import, export and transit tariffs, or fees payable by market players, is abolished.

Compensation for import and export costs is recovered via G or L from the domestic users benefiting from these transactions Compensation for transit is provided in the form of inter-TSO payments as a result of CBT mechanism. However any costs or benefits from the mechanism should be transferred by the TSOs to the domestic users via G or L.

10.2 Present EU CBT regulation (1228/2003)

The present EU regulation 1228/2003 on conditions for access to the network for cross-border exchanges in electricity lays down basic principles with regard to tarification and capacity allocation, whilst providing for the adoption of guidelines detailing further relevant principles and methodologies, in order to allow rapid adaptation to changed circumstances. In its annex are given the Guidelines on the management and allocation of available transfer capacity of interconnections between national systems in Europe

On the following brifely are commented the main articles of regulation.

Article 3: Inter transmission system operator compensation mechanism

1. Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks.

2. The compensation ... shall be paid by national TSOs from which cross-border /flows originate and the systems where those flows end.

5. The magnitude of cross-border flows ... shall be determined on the basis of the physical flows of electricity actually measured in a given period of time.

6.The costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, as far as infrastructure is used for the transmission of cross-border flows, in particular taking into account the need to guarantee security of supply. When establishing the costs incurred, recognized standard-costing methodologies shall be used. Benefits that a network incurs as a result of hosting cross border flows shall be taken into account to reduce the compensation received.

Article 4: Charges for access to networks

1. Charges ... for access to networks shall be transparent, take into account the need for network security and reflect actual costs ... and applied in a non discriminatory manner. Those charges shall not be distance-related.

2. Producers and consumers ("load") may be charged for access to networks. The proportion of the total amount of the network charges borne by producers shall, subject to the need to provide appropriate and efficient locational signals, be lower than the proportion borne by consumers. Where appropriate, the level of the tariffs applied to producers and/or consumers shall provide locational signals at European level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure. This shall not prevent Member States from providing locational signals within their territory or from applying mechanisms to ensure that network access charges borne by consumers ("load") are uniform throughout their territory.

3. When setting the charges for network access the following shall be taken into account payments and receipts ... from inter-TSO compensation mechanism …

4. Providing that appropriate and efficient locational signals are in place ... charges for access to networks applied to producers and consumers shall be applied regardless of the countries of destination and, origin…

Article 6: General principles of congestion management

1. Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals ... Network congestion problems shall preferentially be solved with non transaction based methods …

2. Transaction curtailment procedures shall only be used in emergency situations where ... redispatching or countertrading is not possible … Market participants shall be compensated for any curtailment.

5. TSOs shall, as far as technically possible, net the capacity requirements of any power flows in opposite direction over the congested interconnection line in order to use this line to its maximum capacity... Transactions that relieve the congestion shall never be denied.

6. Any revenues resulting from the allocation of interconnection shall be used for:

a) guaranteeing the actual availability of the allocated capacity;

b) network investments maintaining or increasing interconnection capacities;

c) as an income ...

The main principles governing methods for congestion management as stated in regulation are:

a) Network congestion problems shall preferentially be solved with non-transaction based methods …

b) Cross-border coordinated redispatching or counter trading may be used jointly by the TSOs concerned. The costs that TSOs incur in counter-trading and redispatching must, however, be at an efficient level.

c) The possible merits of a combination of market splitting, or other market based mechanisms, for solving "permanent" congestion and counter-trading for solving temporary congestion shall be immediately explored as a more enduring approach to congestion management.

10.3 CBT in Europe

Generally, technical arrangements for cross-border transmission access as well as “internal” access to the national networks have been designed such as:

- to allow TSOs to always ensure secure network operation, taking into account that they are no longer involved in planning generation dispatch, but have to be informed by market participants about the desired trading transactions and/or the resulting generation dispatch,
- to facilitate the assessment of existing transmission capacities against the transmission demand of market parties in order to anticipate possible network congestion, and to introduce mechanisms for allocating scarce transmission capacity to market parties, and
- to facilitate effective countermeasures to be taken by the TSOs in case secure network operation is immediately threatened by network congestion.

The following principles for cross-border tarification have been adopted at the Florence Forum:

✓ Separation of the treatment of short-term and long-term transmission related economic signals. Short-term signals will be mostly derived from network constraints, while long-term signals have the main purpose of recovering transmission costs and also of providing locational signals, mainly for the sitting of new producers and demands.

✓ At country (or TSO) local level G (for generation) and L (for load) transmission tariffs provide access to the entire IEM without any supplementary border fees.

- ✓ Economic compensations among countries must be established because of the costs incurred by cross-border transactions and loop flows. Compensations should be paid to those countries that incur into extra costs because of cross-border trade, and charges should be levied on those countries that are responsible for these costs. Therefore, there will be no cross-border tariffs, but a compensatory scheme at country or TSO level. The compensations are required because of two reasons:
  - losses that take place in a country because of the existence of cross-border transactions and loop flows;
  - utilization of the networks of other systems because of cross-border transactions and loop flows.

  Therefore the compensatory mechanism consists of three basic steps:

  1) determination of the *compensation* that is due to each country because of the costs that are incurred by cross-border transactions and loop flows;
  2) determination of the charges that each country has to pay in order to compensate others;
  3) a method to reflect the results of the two previous steps in the national tariffs G and L.
- ✓ Use of real flow network models, i.e. models that represent all the existing transmission lines with their actual power flows, in order to faithfully represent the reality of the functioning of the power system.
- ✓ Equal treatment of existing and future lines in the network cost allocation algorithms. This simplifies the network cost allocation procedures and it also allows the automatic treatment of new investments. A posteriori, regulators may decide to establish thresholds or limitations to the compensations corresponding to the existing network.
- ✓ Use of standardized costs, just for the purpose of computation of inter-TSO payments for the different transmission components.
- ✓ Non transaction-based charges. Any charges that may be derived from the inter-TSO payments scheme, because of their intrinsic nature of long-term economic signals, must not depend on the specific commercial transactions among the market agents.

The mechanism of cross-border tarification has been implemented for the first time on March 1 2002 and it has finally succeeded in eliminating tariff "pancaking" in the IEM.

The mechanism considers the inter-TSO compensations as a function of the transit hosted by each country or TSO measured from the flows on the interconnections with the adjacent countries or TSOs. The charges to recover the compensation fund combine two models: "declared exports" and "net-flow".

The next paragraph describes the provisional mechanism of cross-border tariff, details of the cross-border methodology and related formulae used in payments settlement between TSOs in SEE.

10.4 The CBT mechanism in South-Eastern Europe

A specific working group, SETSO TF has been established under the umbrella of ETSO in order to practically facilitate activities regarding the constitution of a competitive Regional Electricity Market (REM) in SEE based on the rules currently in force and being developed in the European Union and integrated into European Union's Internal Electricity Market (IEM).

On the Second Athens Forum (March 2003) SETSO TF was invited, in collaboration with the CEER, to make a proposal of inter-TSO mechanism to be presented at the 3rd Athens Forum. Up to that time only few TSOs receive revenues for transit services: flows passing through neighboring networks are not remunerated for the additional costs incurred by transit.

A SEE CBT mechanism proposal based on the IEM 2003 mechanism was presented by SETSO TF and adopted by the 3rd Forum. The Forum agreed to a six months dry-run period starting from January 1st, 2004. After that it proved to be successful and after the necessary modifications coming from the experience of the parties during the dry run period the CBT mechanism was introduced on a real basis from July 1st, 2004.

In Figure 10.1 is illustrated the SEE region and the participant of the Cross Border Trade mechanism in 2004.

Meanwhile, taking into account experience gained from the dry-run period, SETSO TF published an *operational proposal on SEE CBT mechanism implementation*, presented at the 4th Athens Forum on 26-27 October 2004,. This was based on the 2004 IEM mechanism applied by ETSO this year in most of the European Union as well as in Norway and Switzerland. The mechanism is implemented, under the coordination of ETSO and takes into account the specific situation for SEE region, where the operational conditions for cross-border exchanges include also the island or radial operation mode of 110 kV tie-lines.

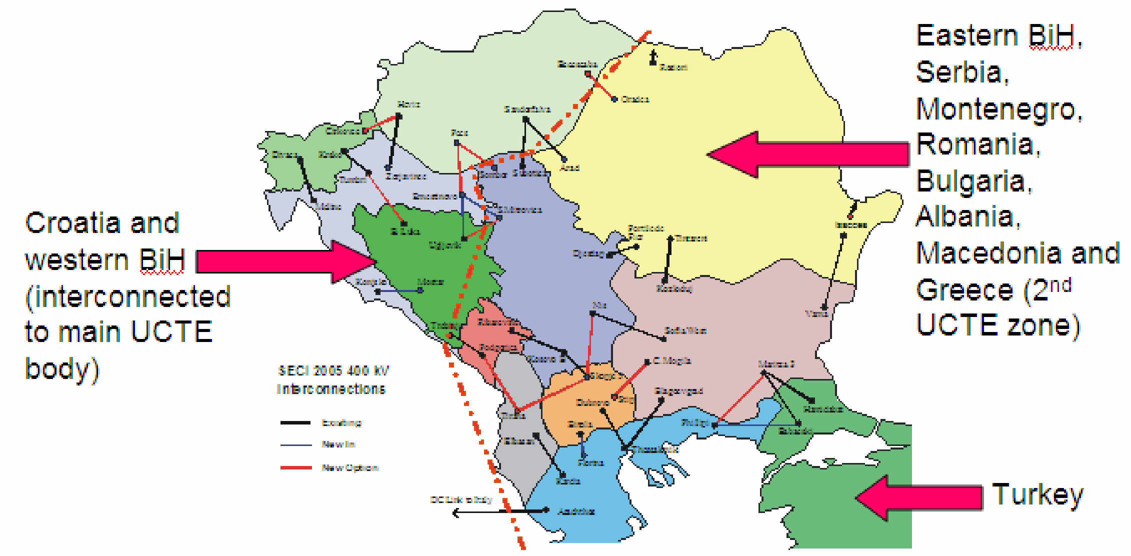


Figure 10.1 The participant of the first phase of CBT in SEE

<u>The principles of SEE CBT mechanism of 2005</u>

The Inter-TSO Compensation (ITC) mechanism described below is established in order to compensate the use of national transmission systems by cross-border trade in SEE region.

For defining the CBT-Mechanism, the following steps have been followed:

1) Definition of the Horizontal Network (HN): a uniform model and criteria for the identification of the horizontal network of each country is applied.
2) Definition of the costs of the Horizontal Network used for transits and of the transmission losses in this network, i.e. the mechanism for the calculation of the CBT-fund and the inter-TSO compensation: it harmonizes the costing scheme for the relevant horizontal network.
3) calculation of transit compensation due by each country using the “transit key”
4) Definition on how the fund for compensation is financed.

10.4.1 1st step: Definition of the Horizontal Network (HN)

The "Horizontal Network" is that part of the transmission system, which is used to transmit electricity between countries and within the country. It contains the transmission system elements that are influenced significantly by cross-border exchanges. This approach supposes that the functions of the network can be split into three parts:

- access of the generation to the "Horizontal Network";
- access of the load to this "Horizontal Network";
- the "Horizontal Network see Figure 10.2 ".

The two first functions constitute the "Vertical Network". For most countries, the "Horizontal Network" consists at least of the 400 kV and 220 kV interconnections, lines and transmission substations. In SEE the interconnections equal or higher of 110 KV, either in parallel or island mode between the parties and with the perimeter countries are taking part in the mechanism

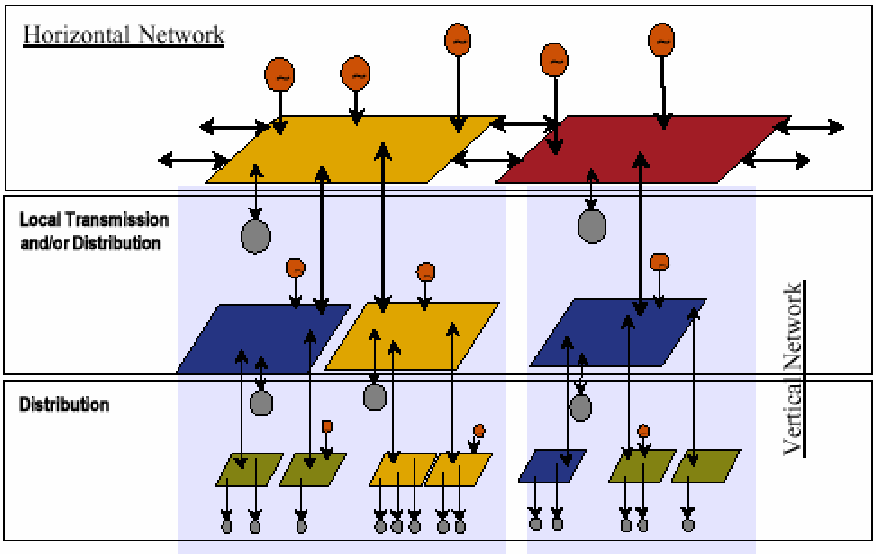


Figure 10.2 Concept of "Horizontal" and "Vertical" Networks

Delimitation of the SEE CBT area

The SEE CBT parties, signatories of the SEE CBT Agreement for 2005 are the following TSOs:

- Korporata Elektroenergjetike Shqiptare "KESH" sh.a. from Albania;
- Zajednicki Elektroenergetski Koordinacijski Centar, pu, (ZEKC) Sarajevo from Bosnia-Herzegovina (B&H);
- Natsionalna Elektricheska Kompania (NEK) from Bulgaria;
- Elektrostopanstvo na Makedonija (ESM) from Macedonia, which has transferred the rights and obligations to the recent established TSO: Makedonski Elektro Prenosen Sistem Operator (MEPSO).
- Elektroprivreda Crne Gore (EPCG) from Montenegro, hereinafter referred to as,
- Compania Nationala de Transport al Energiei Electrice (TEL) "Transelectrica" SA from Romania;
- Javno Preduzece Elektroprivreda Srbije (EPS) from Serbia.

The corresponding SEE CBT area comprises the following countries: Albania, Bosnia and Herzegovina, Bulgaria, FYR of Macedonia, Montenegro, Romania and Serbia.

The CBT area in South-East Europe is presented in Figure 10.3.

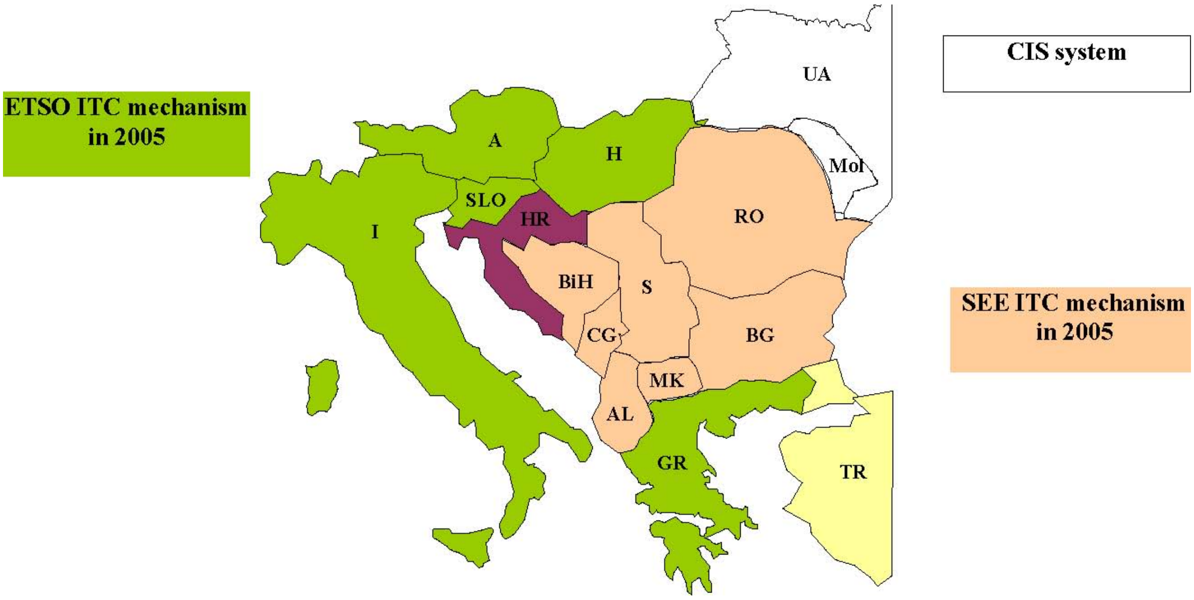


Figure 10.3 The CBT area in South-East Europe in 2005

The Horizontal Network is defined as the set of each country's internal lines significantly affected by cross-border trade. The methodology called Allocation of Transit Flow (ATF)-approach is used in ETSO CBT 2005 mechanism with the scope of definition of allocation of each network element to the Horizontal Network.

The method considers one national network each time, highlighting inner lines and interconnection nodes. Therefore, a standardized transit magnitude of 100 MW is applied between each couple of interconnection nodes and zero flows in all other tie-lines. For a country/TSO with N tie-lines, there are N(N-1) such "one-to-one" transit patterns. In Figure is illustrated the method in case of a country with three interconnection nodes

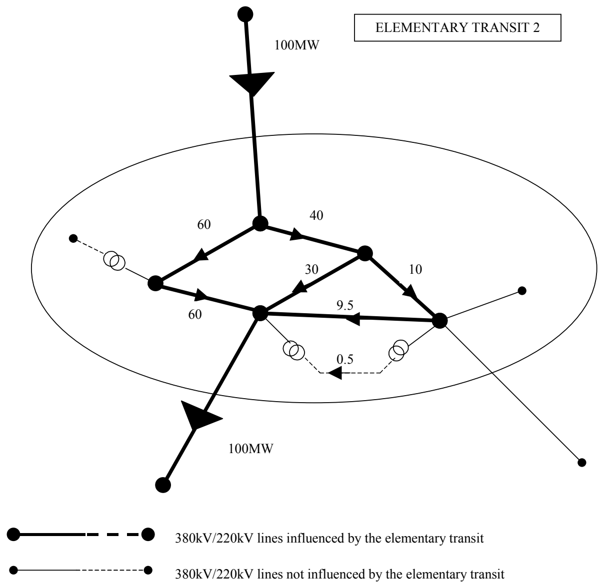


Figure 10.4 Transit patterns for definition of HN

In order to decide whether a given grid element must be included in the horizontal network of a country/TSO or not, the method identifies which elements bear a flow caused by applying the standard transit applied between two tie-lines – that is greater or equal to 1 MW. Elements with transit flows that are lower than the threshold value are removed. The calculations are undertaken country by country, TSO by TSO and CBT party by CBT party respectively.

The ATF method is applied based on DC Load Flow Approximation on an "empty" network. The SPIRA computation tool includes this function called FLOWDC.

All transmission lines, which are usually operated, are put in operation in order to represent the transmission system in normal operation conditions.

10.4.2 2nd step: Annual costs of Horizontal Network

For the definition of HN costs of each TSO in the region, the SETSO TF, in cooperation with respective regulatory authorities, estimated the annual costs (based on replacement costs) for each element of their respective HN. The comparison of the costs arisen from this estimation revealed considerable differences among the involved Countries. Therefore, CEER Working Group of South-eastern Europe Energy Regulators (SEEER) proposed to the SEE TSOs to provisionally adopt a set of average construction standard costs, defined for each element. On CEER/SEEER WG meeting in Athens (25.02.2004) was decided to use the standard costs for the CBT implementation.

According to SEE TSOs the above-defined standard costs are appropriate for compensating the network usage for CBT and they approved their utilization during the implementation of the SEE ITC mechanism starting from January 1st 2005.

The standard costs for lines are given per voltage levels (Euro/km/voltage) and the standard costs for transformers are given per types of transformers using their installed capacity (Euro/MVA).

The standard costs for transformer are defined per installed capacity (MVA) according to the typologies presently operated in SEE. In any case, for deducting construction costs for machines of different size, is applied a polynomial dependency of transformers' price with the installed capacity (basic size: 400/220 KV, 400 MVA, 3 M€). The standard data for transformers are given in Table 10.1 and for lines are

- 400 kV lines : 205,000 €/km;
- 220 kV lines : 150,000 €/km;
- 110 kV lines : 70,000 €/km;

Table 10.1 Standard Cost of transformers for CB cost claim Estimation

Transformer Type	Installed Capacity	Costs	Specific Cost
	MVA	M€	k€/MVA
Transformers 400/220 kV	800	5.04	6.3
	722	4.67	6.5
	630	4.22	6.7
	400	3.00	7.5
	300	2.43	8.1
Transformers 400/110 kV	400	3.00	7.5
	300	2.43	8.1
	250	2.10	8.4
	150	1.44	9.6
Transformers 220/110 kV	200	1.78	8.9
	180	1.65	9.2
	150	1.44	9.6
	125	1.25	10.0
	100	1.06	10.6

Calculation of the Horizontal Network total cost

The quantities of each type of grid elements (km, MVA) should be multiplied by corresponding standard costs in order to obtain the total cost of the Horizontal Network.

Annual cost of the Horizontal Network

The same value of annuity (9%), as was utilized on the preliminary calculation of the SEE CBT mechanism has been applied for the estimation of the annual cost of the Horizontal Network. As example the Table A3.1 and Table A3.2 in Annex 3 report the results of calculation related to assessment of benefits from CBT for Kosovo and Albania over the ESTAP II/1 study period.

10.4.3 3rd step: Cost claim of each SEE CBT party: Transit key calculations

The *share of transits* in the HN is defined by using the "transit key" that according to ETSO CBT mechanism.

This solution gives a result that is a share of the overall amount of the infrastructure costs identified by the ATF-approach.

The transit is defined as the minimum of import and export flows measured hour by hour at the interconnection lines between countries. The transit key is then calculated by dividing the transit by the sum of transit and the consumption of the country (see formula). It is not related to peak capacity but to the average use of the network.

The transit key is calculated according to the following formulae:

$$\xi_k = \frac{\sum_{m=1}^{M} TCO_{km}}{\sum_{m=1}^{M} L_{km} + \sum_{m=1}^{M} TCO_{km}}$$

Where: where k means country, M means first months of 2005 and *TCO (k,m)* is transit in GWh

$$TCO_{km} = \sum_{h \in m} Min(ExFlo(h)_{km}, \operatorname{Im} Flo(h)_{km})$$

L (k,m) Monthly Energy Consumption of Country k [GWh]

ExFlo(h)km Flow on Tie Lines of Country "k" in Export Direction in hour h [MWh/h]

ImFlo(h)km Flow on Tie Lines of Country "k" in Import Direction in hour h [MWh/h]

TCO_{km} gives an image of the load of the horizontal network which is induced by Cross-Border exchanges. Transit is defined as minimum value between imports and exports flows measured each hour and is illustrated in Figure 10.5.

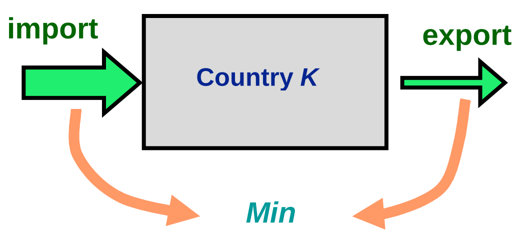


Figure 10.5 Definition of transits of country k

Assessment of cost claim

The share HNC_k of the total cost of the horizontal network in country "k" which will be recovered through cross-border tariffs are calculated by multiplying the HN annual cost by transit key for each country:

$$HNC(T)_k = \xi_k \ HNC_k$$

Where: *HNCk* Horizontal Network Cost of Country "k" [M€/year]

As example the cost claim for Kosovo and Albania are reported in Tables A3.3 to A3.4 in Annex 3 report utilizing the results of calculation over the study period for Kosovo and Albanian power system. Also the data relevant to SEE countries and calculation of CBT relevant to year 2004 are reported in Annex.

10.4.4 4rth step: SEE CBT Fund raising and Financing

The amount of the SEE CBT compensation fund is the result of technical, justifiable and transparent criteria. On the basis of all the above points and taking into account the participation of 7 countries, the fund in 2005 is around 19 M€

Once defined the amount of the compensations, the relevant fund must be collected. The TSOs contributions to the SEE CBT fund are estimated ex-ante and two types of contributions are considered:

A first part that takes into account the contribution from the perimeter countries. This is raised from an **explicit injection fee** of 1€/MWh on the declared exports from exporters/traders of these countries to the area of the signatories of the SEE CBT mechanism.

The perimeter countries are: Moldavia Republic, Ukraine, Hungary, Croatia, Greece and Turkey.

A second (main) part called "net flow" part of the fund: "Net Flow" is defined as the country hourly net flow in export or import directions (algebraic sum of imports and exports). The charge for net flow is the same irrespectively of whether it is in the export or import direction. It is raised from the contribution resulting from the national tariffs included in the "L" and/or the "G" component; the decision is left to subsidiarity and therefore to the decision of the individual TSOs and Regulating Authorities.

In 2005 the export fee contribution disappeared, because it was judged as discriminatory of the transactions on the basis of their injection and withdrawal point.

The concept of "edge countries", defined within ITC mechanism operated in EU, was also adopted in the SEE ITC mechanism. In Table 10.2 are given the neighboring and perimeter countries in SEE CBT area.

Table 10.2 Neighboring and perimeter countries in SEE CBT area

SEE CBT country	Neighboring countries	Neighboring perimeter countries	
		within ETSO CBT area	out of ETSO CBT area
AL	SCG/CG, SCG/S, MK	GR	-
B&H	SCG/CG, SCG/S	-	HR
BG	MK, RO, SCG/S	GR	TR
MK	BG, SCG/S, AL	GR	-
SCG/CG	AL, B&H, SCG/S	-	-
RO	BG, SCG/S	HU	UA, MD
SCG/S	AL, B&H, BG, MK, RO, SCG/CG	HU	HR

The "edge countries" are those countries that border with at least one SEE CBT country and at least one perimeter country. The reasons for the application of this method are:

- For an edge country, with net import both from a perimeter country and a SEE CBT country, the import from the perimeter country (on which an injection fee is already paid) does not cause any transit in the SEE CBT country and must not contribute to their net flow.
- The same applies for an edge country with net export both to a perimeter country and a SEE CBT country.

Taking into account what above, it was therefore considered questionable that perimeter country flows should be included in the calculation of the net-flow contribution to the SEE CBT fund for the edge country. For the application of this concept, a reduction of the perimeter country contribution to the net-flow calculation has been agreed so that:

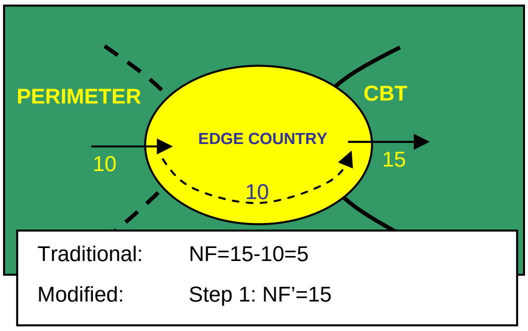


Figure 10.6 Calculation of net/flow in case of edge country in import&export

⇒ First, a preliminary net flow with SEE CBT countries only is calculated considering only flows with SEE CBT countries.

⇒ Second, the preliminary net flow calculated is reduced by an amount equal to the maximum possible transit from a perimeter country to a SEE CBT country through the edge country

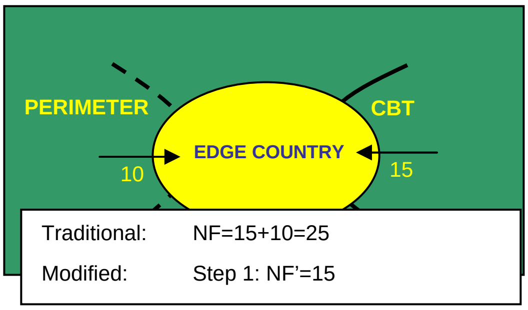


Figure 10.7 Modified calculation of net/flow in case of edge country in import (export)

10.4.5 Clearing Process and Settlement of differences

Settlement is required because each part of the contribution is estimated ex-ante, based on the historical data, while the actual contributions paid to the fund are based on the real data from actual year so each country will receive a payment that may be either higher or lower than the claimed revenue.

As the effective income at the end of the considered year may be different from the expected SEE CBT fund, the settlement of differences shall be executed. The ex-post differences are reported to N+1 year.

10.4.6 ETSO - SETSO interface

The current status for the second semester of 2004 was:

- ETSO charged imports from SETSO area with 1 €/MWh
- SETSO charged imports from ETSO area with 1 €/MWh

In the near-term period few solutions are under investigation by SETSO and ETSO related to :

- An injection fee on physical flows between ETSO and SETSO neighboring CBT parties
- Gradual integration of SEE TSOs into the ETSO CBT mechanism
- One single CBT area in a single synchronous European zone

It is expected that the ITC mechanism in SEE region shall merge with the ETSO ITC mechanism in next future.

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