TECHNICAL APPENDIX

TSO ATTRIBUTES and REQUIREMENTS

1 INTRODUCTION

The purpose of this document is to define the basic requirements of a Transmission System Operator (TSO) both in terms of its perceived duties in the context of the Regional Electricity Market (REM) in South East Europe (SEE) and its integration to the European Union (EU) Internal Electricity Market (IEM). The document first examines the principles already set in existing documents and then defines the TSO requirements within the physical and institutional environment in which these entities will operate. This will enable the comparison of the preparedness of the existing SEE utilities towards a market based regional trade in electricity. This comparison will then form the basis of the commentary on:

- Bottlenecks;
- Transmission capacity;
- Technical standards and procedures;
- Transmission Investment; and
- TSO mechanisms.

2 EXTRACTS FROM EXISTING DOCUMENTATION

In this section appropriate references to existing EU institutional documentation including Council of European Energy Regulators (CEER) are included together with extracts from the documentation of "market facilitator" entities such as the Union for the Coordination of Transmission for Electricity (UCTE) and European Transmission System Operators (ETSO).

The "Strategy Paper on the Regional Electricity Market in South East Europe and its Integration into the European Union Internal Electricity Market" Brussels, 11/11/02, D (2002) requires a system of national but open markets, upon which regional trade can be based, as the logical preparatory step to market opening. Therefore the adhering parties agree that they will:

(1) Create, regulators, independent transmission system operators and government agencies with sufficient administrative capability to actively achieve the aims within the Memorandum of Understanding and this strategy;.

(2) To implement Grid Codes, with common elements across the region that allow basic operation of the grid and do not discriminate against regional trade based on best practices within the EU and according to the UCTE rules. This is to be coordinated and agreed between the Council of European Energy Regulators (CEER) and the Union for the Coordination of Transmission for Electricity (UCTE) with participation from the European Transmission System Operators (ETSO) shall be invited to give its opinion:

(3) To identify all relevant technical norms for the operation of national markets, under the co-ordination and control of ETSO and UCTE by June 2003;

(4) With the assistance of the EC, the adhering parties shall consider the application of the CEER and ETSO guidelines for inter-country trade and commercial codes, cross-border tariffs and congestion management, with suitable adjustment for national circumstances as CEER and ETSO consider appropriate;

(5) To implement transparent financial settlement systems, independent audit, and apply international accounting standards (IAS);

(6) To implement with ETSO and UCTE, an appropriate method for collaboration and information exchange between national dispatch centres;

(7) Adopt an action plan for tariff reform and reduction of non-technical losses;

(8) To implement a system of Regulated Third Party Access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users;

(9) To implement a licensing system for all types of infrastructure facilities and for market participation that is transparent, non-discriminatory and in line with international best practice;

(10) To adopt legislation on competition that is at least applicable to entire energy sector
(11) To draw up and agree an action plan on an annual basis for actions to be undertaken on a national basis by each country in a manner consistent with the objective of optimising the regional electricity system.

CEER TF "SEE Electricity Regulation" Discussion Paper on "The Standard Market Design of the SE Europe Electricity Market (SEEEM)" 07.05.2003 in section 3 defines:

- **"**Transmission providers" are transmission system operators providing third party access under a regulated regime at a single country level operating as profit-making entities from exploiting the transmission infrastructure. They may be subject to an investment obligation under a long-term regulated planning of transmission expansion and reinforcement. Their revenues come from renting the transmission infrastructure at regulated prices.
- **"**Transmission Capacity Adequacy" as infrastructure security of grid equipment and operations and control hardware and software is essential to ensure day-to-day grid reliability and operational security. Regulators supervise compliance of all transmission providers, market participants, and generators interconnected to the grid with electric reliability standards, and that TSOs maintain and expand the infrastructure meeting basic standards for system infrastructure and operational security, including physical, operational, and security practices.

UCTE defines the duties of the "Transmission System Operator" as the neutral and independent provider of the infrastructure and of the system management services that are the necessary prerequisites for the functioning of the market including:

- taking care of the safe transmission of electricity;
- taking care of the reliability and stability of the system;
- balancing supply and demand at any time; and
- maintaining and developing the infrastructure i.e., the networks and related technical facilities.

ETSO pursues the objectives of the development of common principles regarding the harmonisation and establishment of rules in order to enhance network operation and maintain transmission system security facilitating the internal European market for electricity.

3 CONSTRAINTS AND BOTTLENECKS

3.1 UTILITIES' VIEWS ON CONSTRAINTS

During both technical visits and, as part of the technical questionnaire, all utilities provided information on current bottlenecks and proposed or current system developments to alleviate them. The following information has been provided by the utilities.

ALBANIA, KESH

The 220kV interconnection lines between Albania - Kosovo can be 100% loaded in winter when taking import from Greece and from Podgorice into Kosovo.

KESH has indicated that transmission constraints are managed on a day to day basis by limiting demand, by automatic and/or manual load-shedding and by limiting power infeed from, or exports to, other systems.

Reactive power problems exist in Montenegro and Kosovo and reactive power has to be provided by KESH. There is now an agreement with Greece that Albania will only use the 80MVAr available from the Albanian transmission line to Greece. At 110kV the load power factor is approx 0.85 but the 110kV lines are overloaded and therefore take excessive reactive power. Power factor correction capacitors at load points would help to reduce this problem.

BOSNIA AND HERZEGOVINA

EPBiH

No bottlenecks are reported

EPHZHB

Constraints do exist in Bosnia and Herzegovina but when the 400kV transmission lines are rebuilt these are expected to disappear (after July 2004).

EPRS

At present there are many transmission lines and transformers experiencing high levels of loading 70-100% of their rating during the peak and winter demand periods currently reaching some 700-750MW in total. The period of maximum congestion is January following which system congestion is confined only to certain points, where there are only local restrictions due to available transformer capacity. Loading of the connecting 110 kV line from Bijeljina to Lešnica is seasonally restricted because of overloaded line Šabac - Lešnica (EPS). This restriction amounts between 50 and 80 MVA depending on conditions in the EPS electric power system. The majority of these congestion problems are expected to be eliminated following reinstatement of the damaged circuits following which any congestion would be related to market operation.

CROATIA, HEP

While maximum congestion on the HEP transmission system naturally depends on the network configuration and operating power plants congestion in Croatian transmission network, usually occurs under (n-1) transmission outage conditions at high demand periods from December to February, on the southern transmission lines towards Dalmatia and BiH. Most affected lines are 400 kV Melina-Velebit-Konjsko, 220 kV Brinje-Konjsko, 220 kV Konjsko Zakučac) and 110 kV Tumbri-Mraclin.

Power flows on the Konjsko-Melina are limited to 600 MVA due to stability and power oscillations in 400 kV network. This constraint may cause water spillover in

During favourable hydrological conditions the 220/110 kV, 100 MVA transformer at HPP Zakučac is a bottleneck preventing transfer of local generation output to the 220 kV network. The 220 kV Konjsko-Zakučac transmission line also represents a bottleneck in the network during significant generation in HPP Zakučac and HPPs in BiH.

There are some older substations in HEP 110/MV kV transmission network with ten or more line bays. Because of unavailability or outages of some power plants at Zagreb area, overloading of the following lines is possible on a regular basis namely, 110 kV Mraclin-Tumbri 1&2, 110 kV Tumbri-Botinec, 110 kV Botinec-Sopot and DV 110 kV Botinec-TE-TO.

There is also a problem in transmitting the full available output power of TE-TO Zagreb power station at 337 MW over its connections at 110 kV voltage level. In addition switching equipment inadequacies in the TE-TO Zagreb substation leads to overloading of 110 kV TE-TO-Resnik 1&2 circuits.

During high output periods of HPP Dubrovnik and low local consumption, congestion occurs on 110 kV Komolac-Ston circuit.

Natural transmission flows restrictions will be increasing in the future due to many 400 kV and 220 kV transmission lines being of single circuit construction. Further constraints due to system stability considerations are also expected.

MACEDONIA, ESM

Constraint problems have been identified on the north to south connection between Nis, Kosovo B, Skopje, Dubrovo, Thessaloniki. Nis - Kosovo B is one potential bottleneck but this is due to (n–1) criterion, i.e. line outage between Bulgaria and Greece produces bottleneck on above line vice verca. EKC co-ordinates outages. Dubrovo, Thessaloniki 700MW limit is due to protection settings and is under discussion.

Following progressive commissioning of the planned system reinforcements few system constraints or bottlenecks are expected to remain in the future. There are three 400kV interconnections being planned or under construction, connecting:

- Bitola 2 with Florina (Greece) scheduled for commissioning in 2007. The complete documentation is prepared and the project is seeking investment funds.
- Stip with C. Mogila (Bulgaria) scheduled for commissioning in 2006. The international tendering procedure is underway with the project being financed by an EBRD loan.
- Skopje 5 with Nis (SCG) scheduled for commissioning in 2008. Feasibility studies are complete. The project is expected to give better regional security and market opportunities.

MONTENEGRO, EPCG

When Albania operates in three islands there can be voltage problems on the Montenegro to Albania interconnection. When the line from Albania to Greece is in service there can be congestion problems between Montenegro and Albania. Albania is continuously changing the way they operate their system which is not very predictable. Voltage problems are experienced at evening peak load periods when:

- Republika Srpska switches between UCTE1 and UCTE2 zones which removes reactive support to Montenegro.
- There are problems of reactive output of Perucica when operating at full MW output leading to network voltage problems and power output is reduced to provide more MVAr
- The 400kV line from Podgorica 2 to Ribarevina cannot be taken out of service because this causes severe voltage problems in the rest of the network.

There is an urgent need for reactive compensation at Podgorica and the southern part of Montenegro load area.

SERBIA, EPS

Transmission bottlenecks in EPS power system are mainly in 110kV and 220kV networks during the winter period and they strongly depend on generation pattern. Also in winter period some 400/220kV and 400/110kV transformers are often overloaded. In the last three years there are fewer overloads during the winter period because the difference between the peak and minimum load has decreased due to the new tariff system and also the peak power is decreasing. Construction of one new 400 kV line (Subotica – Sombor) – starting autumn 2004 with completion expected at the end of 2006, three new 400/110 kV/kV substations with appropriate upgrades of 110 kV lines (Sombor, Jagodina, Beograd 20) and upgrade of one 400/220/110 kV substation (S.Mitrovica) are currently in progress. After completion of these projects in the next 2 years there will not be any major transmission bottlenecks.

No stability problems have been observed.

UNMIK, KEK

A number of circuits are extremely highly loaded at peak system demand including TS Prishtina 4 to TS Ferizaji, TS Prizreni 2 to TS Prizreni 1, TS Gjakova to TS Gjakova 1, TS Burimi to TS Vallaci, TS Vallaci to TS Kosovo A, TS Vushtrria to TS Kosovo A. In addition the power flow over some 18 transmission lines at 110kVare limited by the rating of their current transformers although in many cases this is not critical in some 7 cases this limitation is considered a material bottleneck.

There are also some peak load limitations due to inadequacy of installed 220/110kV transformer capacity at Kosovo A. At present in order to eliminate these overloads in peak demand periods KEK creates operational islands on the 110 kV grid.

In addition to the above, lack of reactive power support at TS Skopje causes reactive power overloading at Kosovo A power station.

KEK tests the security of the system for (n-1) outage criterion and at 110 kV level the system is found to be not secure for this criterion times high winter demand periods.

There are a lot of material transmission bottlenecks related to the current system which leads to daily operation of the system on almost on an emergency footing.

There are bottlenecks on some of the 110kV rings which can only be solved by load shedding. Some new substations have been built but more are required. Podujeva (220kV turn in) and Pristina 5 (110kV spur from Kosovo A) are complete. Although high voltage Interconnectors have sufficient capacity, the 110kV lines to Serbia can only be radial feeders because flows cannot be controlled. It is anticipated that connection of UCTE1 and UCTE2 zones will not significantly change the flows if the generation pattern remains the same.

3.2 CONCLUSIONS ON UTILITIES VIEWS

Most of the constraints in the 400kV and 220kV will be alleviated with the refurbishment of damaged equipment and/or construction of new proposed lines. This will resolve constraint problems that might arise due to the bulk transfer of electricity. It is understood that the reconnection of the two UCTE synchronous zones has had little effect on constraints. Under some generation patterns it has alleviated some constraints in the north of Serbia as demand in this area can now be fed from both the north and the south.

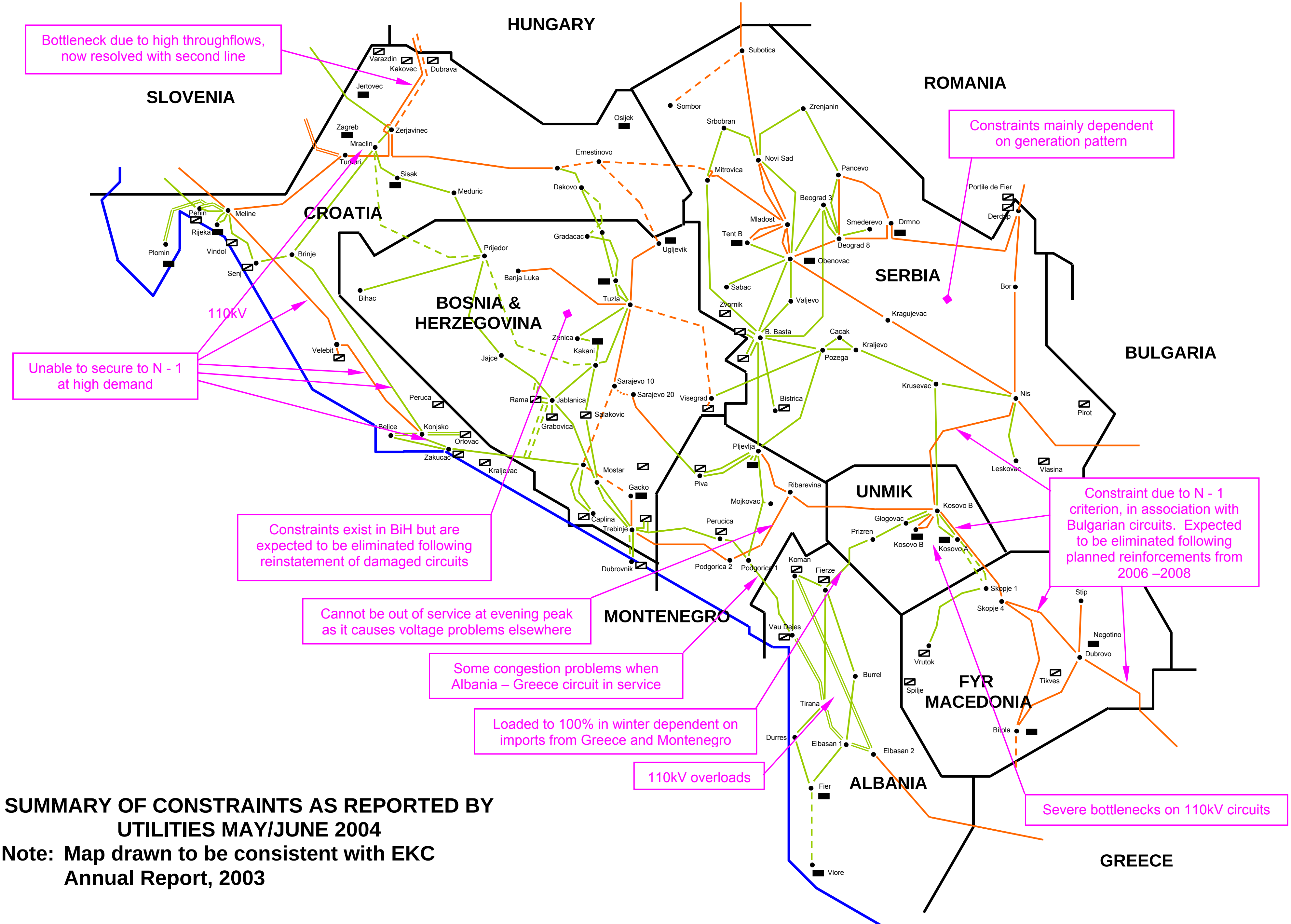
Many countries/jurisdictions have 110kV bottlenecks which, although not affecting bulk transmission of electricity, cause local problems which in some cases cause inability to meet the n-1 criterion, inability to take outages, and, in extreme cases can only be solved by load shedding. Clearly, although utilities regard 110kV as a transmission voltage, only 400kV and 220kV circuits have a material effect on transfer capability and through flows. Whilst restrictions at 110kV have effects on local supplies and may limit the output of some generation on a local level they will not have a significant effect on the market.

Most utilities use summer and winter line ratings as a means of maximizing utilization of transmission assets, but none use any more sophisticated methods such as winter and autumn or dynamic line ratings.

Most utilities would strongly there to be no stability problems within their systems. However, none have carried out studies to determine this, so it is possible that latent and undetected stability problems may exist for some conditions. The establishing of the SECI database, and subsequent study work, will resolve this issue. However, in the mean time, there must some uncertainty over possible constraints due to stability problems.

Some utilities report severe voltage constraints due to insufficient reactive power or inability to provide reactive power at the right parts of the network.

All utilities are reticent to speculate on the effects the electricity market may have on constraints.



SUMMARY OF CONSTRAINTS AS REPORTED BY UTILITIES MAY/JUNE 2004

Note: Map drawn to be consistent with EKC Annual Report, 2003

4 AVAILABLE CAPACITIES

4.1 NET TRANSFER CAPACITY IN SOUTH EAST EUROPE

ETSO uses the concept of Net Transfer Capacity (NTC) as a non-binding indication of the cross-border transmission capacity available to the market[1].

NTCs have the following characteristics:

- Published twice yearly and are indicative only and non-binding.
- Existing power exchange programs are built in – NTC indicates the remaining capacity only.
- Attempt to overcome the reality that cross-border transfers cannot be considered in isolation.
- Are of indicative value only as they do give no indication of the relationship between flows on different borders.
- Two sets of definitions exist; one related to programme values and one related to physical power flows.
- Programmed exchanges and actual exchanges often differ considerably in a highly interconnected (meshed) system.

The ETSO definition document [Definition of Transfer Capacities] sets out a method for determining NTC, using the following notions:

- Total Transfer Capacity (TTC) – maximum exchange programme between two areas compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance.

- Transmission Reliability Margin (TRM) - security margin that copes with uncertainties on the computed TTC values arising from: unintended deviations of physical flows during operation due to the physical functioning of load-frequency regulation; emergency exchanges between TSOs to cope with unexpected unbalanced situations in real time; inaccuracies, e. g. in data collection and measurements.

- Net Transfer Capacity (NTC) is defined as: *NTC = TTC - TRM*. NTC is the maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions.

- Already Allocated Capacity (AAC) - total amount of allocated transmission rights, whether they are capacity or exchange programmes depending on the allocation method.

- Available Transmission Capacity (ATC) - the part of NTC that remains available, after each phase of the allocation procedure, for further commercial activity. ATC is defined as: *ATC = NTC – AAC*.

4.2 AVAILABLE CAPACITIES IN THE BALKANS

There are no published NTC values for the Balkans, and it is not possible to estimate available capacities as this requires detailed knowledge of AAC (Already Allocated Capacity) and in any case these will change in the future.

It is however possible to indicate the relative strength of the transmission system between jurisdictions. The table below shows inter-jurisdiction transmission capacities calculated as 100% of the combined rating of all 220 kV and 400 kV cross-border transmission circuits. These capacities will be well in excess

[1] Definition of Transfer Capacities in Liberalised Electricity Market - ETSO paper, April 2001

of any NTC and the maximum transfers recorded in the EKC annual report, which are included here for comparison.

FROM	TO	COMBINED THERMAL CAPACITY MW	MAXIMUM RECORDED TRANSFERS MW
Albania	Greece	1200	300
	Montenegro	257	160
	UNMIK	562	140
BiH	Croatia	3805	Not given(1)
	Montenegro	1990	70
	Serbia	514	340
Croatia	Hungary	2200	Not given(1)
	Serbia	3310	Not given(1)
	Slovenia	3950	Not given(1)
Macedonia	Greece	1100	480
	UNMIK	1860	150
Montengro	Albania	257	160
	BiH	1930	480
	Serbia	514	Not available(2)
	UNMIK	1250	Not available(2)
Serbia	BiH	514	190
	Bulgaria	1100	200
	Croatia	3310	Not connected(3)
	Hungary	1110	Not connected(3)
	Montenegro	514	Not available(2)
	Romania	1100	200
	UNMIK	1555	Not available(2)
UNMIK	Albania	562	150
	Macedonia	1860	520
	Montenegro	1250	Not available(2)
	Serbia	1555	Not available(2)

(1) Part of UCTE1 synchronous zone and not, therefore, reported by EKC
(2) Given as combined Serbia and UNMIK transfer
(3) No connection until UCTE1 and UCTE2 synchronous zones are reconnected

The capacities shown in the above table are simply the combined thermal capacities of the 400kV and 220kV circuits between the jurisdictions. They do not take into account voltage or stability limitations, and do not consider the (n-1) criterion which will significantly reduce the actual transfer capability. Nevertheless, they do give some indication of the relative transfer capabilities. Actual transfers are significantly less than the thermal capacities shown.

5 CROSS-BORDER TRADE (CBT) MECHANISM

Related to available capacities is the need for a mechanism to compensate for the use of national transmission assets by cross-border trades (transits). ETSO have proposed a revised mechanism in a 2002 report[2]. The proposed compensation mechanism relies on the following notions:

- Definition of the Horizontal Network (HN) in each trading area – by examining representative load-flow situations, and removing non-transit flow, the participation of each transmission asset is determined for all possible standard transits (a 100 MW in-and-out flow through the system). For

[2] ETSO Proposal for 2003 CBT Mechanism, 11 October 2002

any given actual transit, the participation of each transmission asset can then be determined by superposition (addition) of the component standard transits.

- Definition of the costs of HN used for transits. Each TSO will use it ‘regulatory asset’ base to determine the annual cost of its transmission assets. A calculation is performed to allocate these costs to the particular transit flow.

- The transit costs are paid from an ETSO compensation fund. The required value of the fund is determined in advance and it is then sourced from: declared exports (each TSO charge a per MWh for all declared exports); a ‘net flow’ charge based on the hour-by-hour net import/export from each region; and a balancing amount charged to exporting countries (if required).

6 “SOFT MEASURES” TO INCREASE TRANSMISSION CAPACITY

Low-cost measures to increase cross-border transmission capacity fall into two categories of inexpensive technical improvements to specific constraints (e.g. the rating of a particular transmission circuit), and improved methodologies for determining and allocating transmission capacity.

6.1 INEXPESIVE TECHNICAL IMPROVEMENTS

Seasonal Line Rating (e.g. winter/summer rating)

Most utilities within the region have stated that they use winter and summer ratings. Although some measure of enhanced capability could be obtained by using spring and autumn ratings additionally, it is not expected that this would significantly increase allowable transmission flows, although it could assist in local problems.

Static Up-rating of Transmission Circuit Capacity

In some instances the thermal capacity of a transmission circuit is limited by a small number of relatively low hanging spans. Re-tensioning of these spans can allow the whole circuit to operate at the higher temperature and therefore have a higher static current rating.

Dynamic Line Rating

There are a number of techniques for dynamically rating a transmission circuit. Some techniques require the conductor tension or sag to be measured or observed at critical spans. Others use thermal replica software combined with observations of the prevailing weather.

Many utilities are aware of this possibility but none have considered using it, possibly because of complexity and investment costs

Reactive Compensation

Many of the SEE region utilities do not have sufficient reactive compensation especially for the load power factor correction or for providing voltage support at critical parts of the network. This means that large quantities of reactive power are being transported across the network, increasing losses and reducing line capacity as well as presenting voltage quality problems. Even small quantities of inexpensive reactive compensation can provide significant relief in the short term.

Other Inexpensive Technical Improvements

- auto-re-close; most utilizes already use this
- single-pole tripping; many utilities already use single-pole tripping

- line surge arresters for lightening prone circuits; line surge arrestors can significantly reduce the number of faults on lightning prone circuits, particularly if strategically placed at points where there is a high incidence of lightning strikes. No utilities have considered this possibility. It does, however, require investment in lightning location equipment and surge arrestor hardware. Utilities appear reluctant or have difficulty in considering such investments.

6.2 METHODOLOGY IMPROVEMENTS

The methodology improvements include[3]:

Co-ordinated Capacity Allocation

For reasons of pragmatism, the current UCTE methodology for determining NTC (Net Transfer Capacity) is a simplification of what is theoretically possible. The uncertainly introduced by the simplification is overcome by generous TRM (Transmission Reliability Margin) which at times, results in under utilisation of the transmission system.

The current NTC methodology is a simplification in a number of ways:

- Base Case Exchanges (BCE - existing exchange programs between neighbours) do not necessarily match the cross-border power flows and the values are determined by each TSO to suit their own purposes.
- Actual locations of generation and consumption for a particular transaction are ignored.
- Borders are evaluated in isolation, without regard of capacity allocation at others.

ETSO have proposed an improved methodology termed "Co-ordinated Auctioning". The essential feature of this approach is simultaneous allocation of capacity on several (and, ultimately, all) relevant borders, taking into account the physical impact of transactions from specified generation and load pairs.

Cross-Border Congestion Management

Congestion management procedures (e.g. re-dispatch across a constraint) do not increase transmission capacity per se, however when deployed in a theoretically optimal way, they maximise transmission system utilisation, which amounts to the same thing.

If no congestion management is employed, a large amount of capacity must remain unallocated to cater for the very worst case eventualities. This is clearly inefficient. Similarly if "infinite" transmission capacity is offered to the market, all congestion must be handled by congestion management which is also inefficient (e.g. consider the likely case where there is a permanent constraint in the system).

Optimal use of congestion management is clearly a complex problem, but as with all "soft measures", it promises to ultimately be a very cost-effective way to increase usable transmission capacity.

A large number of optimal congestion management methodologies have and are being conceived and evaluated.

Probabilistic Evaluation of Operational Uncertainties

Evaluation of network security is an integral part of determining TRM and hence NTC. Generally the evaluation takes into account contingencies (e.g. circuit trippings), "realistic" generation dispatch patterns, temperatures, weather, expected load variations etc. These assumptions are often based on past experience and practice.

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[3] This section includes a brief summary of the corresponding section in "Analysis of Electricity Network Capacities and Identification of Congestion", written for the EC by CONSENTEC Consulting.

Although complex, this deterministic approach rarely takes into accounts second-order affects and inter-dependencies between assumptions. A probabilistic evaluation offers a large range of theoretical improvements, e.g.:

- weather-based correlation between contingencies and system load (e.g. a winter storm may increase the probability of circuit tripping due to lightning and also increase electrical demand).
- short-term overload capacity of equipment would vary based on pre-contingency loading.

Whilst in theory very promising, probabilistic evaluations may be difficult to implement. The increased complexity of the approach may yield less transparent results, which may be used more cautiously, thus negating some of their advantage.

Transparency and Harmonisation

The above techniques are all heavily reliant on the quality and consistency of information provided by the TSOs.

Harmonisation of best practices in all aspects of operational planning, security analysis, operational standards etc would ultimately lead to increased efficiency of operation. Ultimately some form of consolidated operation function would seem to offer the best possible situation.

Currently TSOs provide only high-level (bundled) information to the market (e.g. BCE – base case exchanges). The underlying definitions, statistical evaluation and presentation of this information vary across TSOs. Successful implementation of these "soft measures" would require more and more frequent sharing of low-level information.

Congestion Management Methods

ETSO have published a paper[4] which evaluates various market based methods for managing congestion. The following is a brief summary the techniques covered:

- Curtailment based on published NTC
- Auction method
- Market Splitting
- Re-dispatching
- Cross-border coordinated re-dispatching (CCR)

Curtailment based on published NTC

NTCs summarise a complex situation and in some situations they represent an over-simplification which can mislead market participants.

When NTCs are used as the upper limit on transmission, they will often result in under-utilisation of the transmission system. NTC curtailment is the simplest method of congestion management, and while it has obvious disadvantages, it does have the one advantage that it does not require a cost allocation method.

Auction method

There are a number of auction variants but the basic concept is that NTCs are auctioned amongst market participants.

[4] Evaluation of Congestion Management Methods for Cross-border Transmission, ETSO, 1999.

The auctioning method is a simple extension of the basic NTC idea and does not require the TSOs to provide additional information to the market. The system suffers from the drawbacks inherent to NTCs, namely under-utilisation and over-simplification of the actual constraint situation.

Market Splitting

Market splitting attempts to manage a constraint by pricing energy higher in areas into which transmission is constrained and lower in areas out of which transmission is constrained. In essence, market splitting uses market forces to control demand and production either side of a constraint. The main advantage of this method is that all market participants receive a price signal which should encourage efficient generation investment and consumption behaviour.

Market splitting is not feasible on large interconnected systems. The system works best if there is a common market structure on both sides of the constraint. Market splitting can operated together with other congestion management techniques.

Re-dispatching

Re-dispatching is simply the process whereby a TSO in an area of constraint will re-dispatch generation in their control area. The cost of this less economic generation dispatch is borne by the market participants involved in the cross-border transactions.

Cross-border coordinated re-dispatching (CCR)

CCR is an extension of re-dispatching within a single-TSO re-dispatch and of course requires significantly more coordination between TSOs.

7 OPERATIONAL PROPOSAL ON CBT MECHANISM IMPLEMENTATION IN SOUTH-EASTERN EUROPE REGION

This has been described in detail in a SETSO Task Force Document “CBT mechanism in South-Eastern Europe for July-December 2004”.

According to the conclusions of the second Athens Forum (AF) taking place in Rome on 26 to 27th of March 2003, SETSO TF was invited, in collaboration with CEER, to make a concrete proposal on Inter TSO compensation mechanism to be presented to the 3rd AF. The Forum delivered its firm commitment for the introduction of a Cross Border Trade (CBT) mechanism in South-eastern Europe (SEE) countries on January 1st 2004, on the basis of the ETSO proposal, for a period of six months on a virtual test basis (‘dry-run simulation’ without real exchange of funds). The CBT mechanism was introduced on a real basis in July 2004.

8 CBT MECHANISM IN SOUTH-EASTERN EUROPE FOR JULY - DECEMBER 2004

Based on the agreements reached during the past Athens Forum meetings as well as on the last one celebrated on 3-4 June 2004 in Athens and based on the feasible results of virtual CBT mechanism successfully run during the first half of 2004 in the region, the South-eastern Europe (SEE) TSOs have implemented, under the ETSO umbrella, the described mechanism to compensate the use of national transmission systems by cross-border trade (CBT mechanism) in SEE region for the period July-December 2004. This is described in more detail in an ETSO document[5].

[5] CBT mechanism in South-Eastern Europe for July-December 2004

9 DEFINITION OF TSO REQUIREMENTS

Based upon the above and numerous other documents, as well as European and international best practice the TSO requirements can be summarised as follows:

1. Ownership and operation of the assets forming the transmission system; The TSO should be the owner of the assets forming the transmission system and operator of these assets. The TSO is not itself a market party, but the provider of the infrastructure and of the system management services that are the necessary for the functioning of the market.
2. Develop and maintain an efficient, co-ordinated and economical transmission system; The TSO shall plan, develop, maintain, and operate the transmission system and its interconnections based on best practices within the European Union and according to the UCTE co-ordinating rules.
3. Develop transmission system within security standards; The TSO shall plan, develop, maintain, and operates the transmission system and its interconnections to other systems in a secure and stable manner complying with electric reliability standards.
4. Enable Regulated Third Party Access; The TSO shall implement a system of Regulated Third Party Access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users.
5. Establish Grid Codes and compliance verification processes; The TSO shall implement Grid Codes, that have common elements across the region and that allow basic technical operation of the grid ensuring security, reliability and quality of the electricity supply and harmonised operation of interconnected electric power systems.
6. Set non-discriminatory connection and use of system charges; The TSO shall implement a system of Regulated Third Party Access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users.
7. Set interconnection charges based on CEER and ETSO Guidelines; The TSO will apply the CEER and ETSO guidelines for inter-country trade and commercial codes, cross-border tariffs and congestion management, with suitable adjustment for national circumstances as the CEER and the ETSO consider appropriate.
8. Facilitate Market Operation, Inter Country Trades and Manage congestion; The TSO shall play a pivotal role in facilitating market operation and inter-country trades by applying CEER and ETSO Guidelines.
9. Contract for Ancillary Services; The TSO is the provider of the infrastructure and of the system management services such as the Ancillary Services such as active and reactive power reserve and black start that are the necessary prerequisites for the functioning of the market and essential to ensuring the secure and reliable operation of the system within the set security and quality of supply standards.
10. Schedule and dispatch generation; The TSO is responsible for the safe operation of the system balancing supply and demand at any time by scheduling and dispatching generation or balancing increments or decrements.
11. Administer the settlements process; The TSO shall implement transparent financial settlement systems, set principles for apportioning of cost and apply international accounting standards (IAS) to complement a system of independent audit.
12. Facilitate information exchange between national dispatch centers; TSO shall implement, in collaboration with ETSO and UCTE, an appropriate method for collaboration and information exchange between national dispatch.

9.1 THE TSO FUNCTION IN THE PRE-MARKET ENVIRONMENT

In order to define the functional requirements of the TSO in a market environment it is advantageous to define the core business of a TSO function in the pre-market environment. This will enable a good base for understanding the additional;

- competences that need to be acquired;
- technical and financial mechanisms, processes and procedures that need to be introduced;
- organisational changes necessary;

for ensuring successful transition to market operation.

This process will also highlight the necessary institutional changes that need to be brought about by the governmental authorities.

In international best practice the core activity of the TSO function is to maintain the generation and demand balance at all times as well as continuity of supply to all customers connected to the power system. In order to achieve this, the TSO function within a utility conducts the following activities:

1. Load forecasting;
2. Operational planning;
3. Generation and transmission outage coordination;
4. Scheduling and dispatch of generation and interconnection transfers;
5. System constraint management;
6. Voltage control;
7. Frequency control;
8. System emergency management; and
9. System performance monitoring.
10. The above core activities would be augmented by support activities in:
11. Longer-term planning;
12. Project management and construction; and
13. Maintenance.

In order to undertake its core duties in a competent manner the TSO function is furnished with the following guiding rules and facilities:

1. Defined security and quality of supply criteria for planning and operating the system;
2. Defined overall reliability requirements expressed in terms of probable incidence of loss of supply;
3. Criteria for minimising transmission system capital and operating costs;
4. Minimising the overall cost of generation to meet the demand i.e., optimal operation of generation;
5. SCADA/EMS system to enable control of the power system and its components;
6. Software for carrying out system security and supply quality analysis;
7. Facilities for communications, protection, metering and monitoring system performance;
8. Comprehensive set of processes and procedures for planning and operating the system; and
9. Operational staff that are trained to plan and oversee the operation of the system.

Clearly the move to market operation represents significant changes in the industry structure where new interfaces are introduced with clearer defined lines of responsibility and obligations. The core functions of the TSO are required regardless of the industry structure. However, the clarification of TSOs pivotal position in market operation means not only strengthening of its technical duties and competences but also introduction of new skills, disciplines and the organisational structures that are required to manage the function in the new market environment. These requirements are analysed in the next section.

9.2 STANDARDS AND PROCEDURES

The purpose of planning and operational security and quality of supply standards is to provide a co-ordinated set of criteria and methodologies which must be used in the planning, operation and maintenance of a transmission system, and to ensure compliance with Grid Code and Transmission Licence requirements as applicable to the transmission utility concerned.

The primary aim of transmission planning and operation is the maintenance of the integrity of the bulk transmission system for foreseeable eventualities. It may be considered that the adequacy, security of supply to any particular load or area is an outcome of this primary aim.

In addition, any transmission or operational plan proposed for adoption within the planning and operational standards, must ultimately be justifiable taking account of economic, financial, strategic and environmental considerations. These considerations would be in accordance with the economic and environmental obligations established for the utility under the terms of the Grid Code and/or the

Transmission Licence. In order to comply with these obligations the utility needs to set up its own procedures and train its staff in the implementation of these procedures.

As a minimum security and quality of supply standards need to define what constitutes the transmission system, the contingencies against which the transmission system should be secured, the acceptable or unacceptable effects and normal operational requirements.

Grid Codes and Licences are being drafted and developed for all the countries are involved. These documents (of which few are currently complete) are likely to contain standards and conditions that compliment, and may be more specific than, the UCTE rules. Thus utilities will not only need to comply with UCTE requirements, but also with in country statutory regulations.

The Grid Code and Transmission Licence are statutory and high level documents which, in normal circumstances, will contain the parameters to which the transmission system within the country is expected to perform and the parameters that the transmission utility is expected to achieve at the interface with its customers. This will include voltage performance, frequency performance and circumstances in which loss of supply may be acceptable. Normally, the utility will be required to report to the regulator on its performance against these high level parameters. In addition, the Grid Code and/or the Transmission Licence usually requires the utility to prepare a set of standards that will ensure that the planning and operation of this system is carried out in such a way as to meet the high level parameters at all times unless unusual and unforeseeable circumstances pertain. These would be the planning, operational and quality of supply standards, which may be separate documents or all contained in a single document. These standards are public domain documents and can be used to determine the need for, and justify, transmission reinforcements, show efficient and optimal operation of the system, and demonstrate the quality of supply that a customer may be expect, allowing the customer to plan his own system and equipment requirements.

The Grid Code will also contain the requirements for data transfer between parties. Where utilities are vertically integrated (as has been the case) information flow is between departments and divisions and occurs with few problems. Once unbundling and privatisation takes place information flow becomes much more restricted, and is often thought to be commercially sensitive, and as a consequence there are specific requirements for data transfer between all parties so that each has sufficient information to plan and operate his own system.

Most utilities have significant documentation that will assist in running their systems under UCTE rules and in compliance with the requirements of an electricity market. Since all utilities are connected to either UCTE I or UCTE II zones, operation up to now has ensured that utilities are generally compliant with UCTE rules; nevertheless some utilities are more advance than others – some have comprehensive sets of rules while others rely on custom an practice.

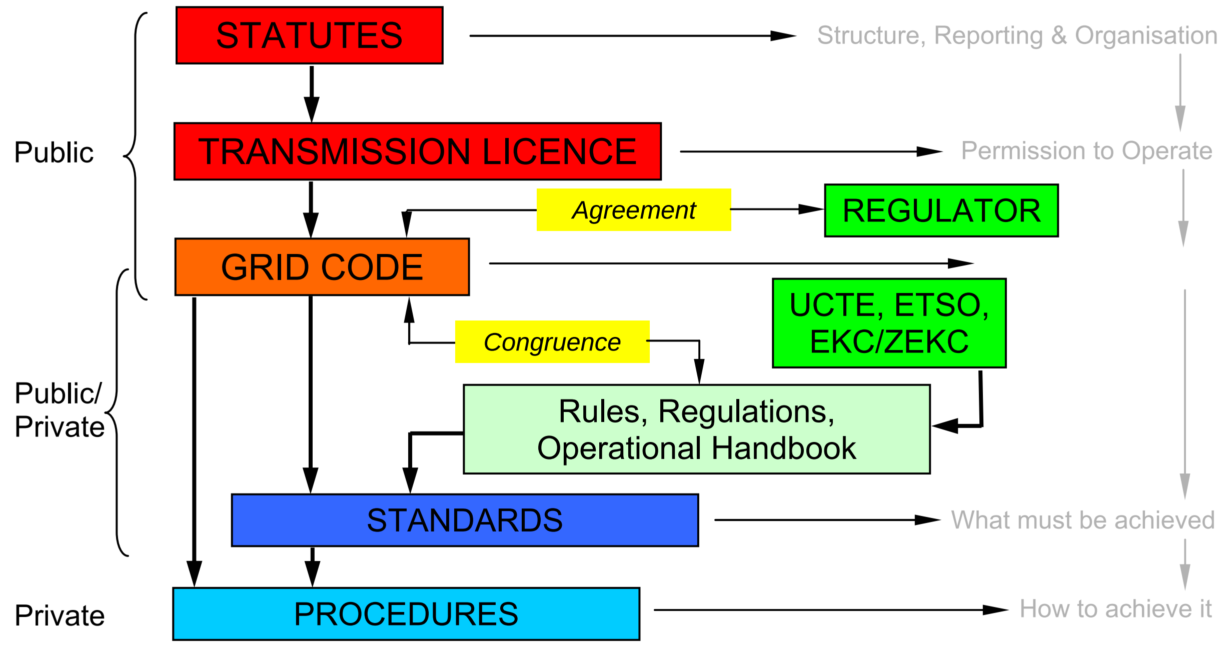
Therefore, each utility will need a set of planning and operational standards that will determine how the system is run to conform with statutory and UCTE regulations, and to specify the quality of supply that the utility is expected to achieve.

It must also be noted the UCTE handbook supplies <u>only</u> an operational set of rules and planning is specifically excluded. It is, therefore, essential that a comprehensive set of planning and operational planning rules are developed by each utility to ensure that, on the day, the UCTE operational rules can maintained.

The development of standards and procedures forms part of a hierarchical structure of documents which regulates how the utilities behave in a co-ordinated transmission system.

The creation of a set of a finalised set of standards cannot be achieved and agreed until all statutory documentation is in place. Unfortunately there are no formally accepted Grid Codes within the countries that are part of this project. Nevertheless, it should be possible to draft standards based on draft Grid

Codes, where they exist, and expectations of what the Grid code will contain. Such draft standards can then be modified when final Grid Codes are in place.



Standards will need to contain as a minimum:

The Transmission System

- A definition of what constitutes a transmission system and what are the customer interfaces;

Contingencies

- A definition of secured contingencies for system planning and performance criteria (including permitted voltage and frequency variations under normal and system contingency conditions);
- Supply capacity following secured contingencies;

Transmissions System Performance

- Frequency control;
- Target Area Control Error performance;
- Voltage performance on the transmission system and at the customer interface;

Connection Arrangements

- System design criteria; generator and user connection arrangements; and

Special conditions for connection of generators including special protection, voltage and frequency control facilities.

To ensure consistent implementation of these standards each utility will require a set of planning and operational procedures (or rulebooks) to set out what work is required and how it is to be done in order to meet the standards. These procedures will ensure consistency across and within departments. Much of what would be contained in procedures may already be done by custom and practice; however, such custom and practice needs to be codified so that there is a clear understanding of what must be done and so that there is a uniformity of working practices. This not only allows continuity across time scales and across disciplines, but also ensures that vital techniques do not become the prerogative of a single person or department. In addition there will be requirements to specify how the data transfer required by the Grid Code is achieved, who in the company is responsible, and how it is managed and verified.

As a minimum it would be expected that planning procedures would contain:

Data

- Data registration, administration and usage;

Long Term System Planning

- Demand estimation in planning time scales;

- Planning study requirements and methodology;
- Outage planning in planning time scales;
- Criteria for long term system development;
- Long term planning for interconnections;

Customer Services

- Connection application planning;
- Opportunities for connection to the system;

Ancillary Services

- Measurement requirements and accuracy; and
- Ancillary service provision and confirmation of performance.

Similarly it would be expected that operational procedures would contain:

Compliance

- Methodologies for achieving grid code compliance;

Operational Planning

- Demand Estimation for Operational Purposes;
- Outage Planning in operational time scales;
- Transmission system safety coordination (including cross boundary working);
- Communications & SCADA systems
- Management of customer interfaces;

Ancillary Services and Control

- Obtaining and managing generation reserves;
- Obtaining and managing ancillary services;
- Primary and secondary load frequency control;
- Management of Area Control Error
- Transmission system voltage control and reactive power management;

Contingencies

- Contingency planning and system restoration;
- Control incident centre and emergency evacuation;

Reporting

- Internal and regulator event reporting;
- Annual report to the regulator;

Other procedures may be required to cover the specific circumstances of particular utilities especially in terms of managing directly connected customers and interconnection transfers

9.3 DEFINING THE TSO FUNCTIONAL REQUIREMENTS IN A MARKET ENVIRONMENT

From the above information the TSO functional requirements can be defined in three specific categories namely the requirements relating to:

1. Basic TSO mechanisms and competencies associated with the core duties of managing the transmission system and facilitating market operation shown in Table 1;
2. Essential TSO Organisational Requirements and Associated Activities/Competences in a Market Environment shown in Table 2; and
3. Essential Institutional Requirements and Associated Activities/Competences enabling a TSO to operate in a Market Environment shown in Table 3.

The first set of TSO requirements relate to the core TSO mechanisms and in the run up to market operation these competences will need to be strengthened and new processes shown in bold in Table 1 will need to be added.

Table 1. Basic TSO Duties and Competences in a Market Environment (Additional core skills required for market operation indicated in bold)

TSO DUTIES	ACTIVITIES/COMPETENCES
1. Asset Ownership and Operation	• Asset Register • **Definition of Asset Boundaries with Generation and Distribution entities** • Asset Replacement/Refurbishment and Investment Policy
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Load Forecasting • System Planning • System Operational Planning • Security and Quality of Supply Standards • Power System Analysis Capability • UCTE Rules • **CEER and ETSO Guidelines** • **Establishing Ancillary Services Requirements** • Maintenance Practices • Construction Project Management
3. Enable Regulated Third Party Access	• **Grid Code (Connection Conditions)** • **Connection Agreements** • **Use of System Charging Tariffs** • **Compliance Processes and Monitoring**
4. Establish Grid Codes and compliance verification processes	• **Grid Codes** • **Compliance Verification and Testing**
5. Set non-discriminatory connection and use of system charges	• **Use of System Charging Tariffs**
6. Set interconnection charges based on CEER and ETSO Guidelines	• **Interconnection Charging Tariffs (Cross-Border Tariffs)** • **CEER and ETSO Guidelines**
7. Facilitate Market Operation, Inter Country Trades and Manage Congestion	• **Inter-country Trading Agreements** • **Commercial Codes** • **Cross-Border Tariffs** • **Congestion Management**
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• **Ancillary Services Requirements** • **Ancillary Services Pricing Principles** • **Ancillary Services Contracts** • **Ancillary Services Contract Delivery Monitoring**
9. Schedule and dispatch generation	• Load Forecasting • SCADA, EMS and other operational facilities that **include mechanisms enabling market operation** • Power System Analysis Hardware and Software • System Operation • **Operational Procedures** • **Ancillary Services Requirements** • **System Incident Investigation** • Constraint and **Congestion Management** • **Grid Code and Scheduling and Dispatch and/or System Balancing Code** • **Management of Balancing and Settlement Information**

10. Administer the settlements process	• **Use of System Revenue Accounting** • **Administration of Energy Accounts Settlement** • **Dispute Resolution Processes**
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• **Grid Code (Data Registration Code)** • **Data Registration and Exchange Facilities** • **Sufficient metering and data collection facilities to enable market operation and billing** • **Market Information System** • **Regulatory Reporting Requirements** • **Connection Opportunities to the system for generation and demand over the next 5-10 years** • **Information Exchange Protocol with UCTE** • **Information Exchange Protocols with Distco's and Neighbouring Utilities** • **CEER and ETSO Guidelines**
12. Staff Skills and Training	• **Ensuring adequate staff skills and training in traditional utility management and technical competences**

Table 2. Essential Additional TSO Organisational Requirements and Competences for the TSO to operate in a Market Environment

ORGANISATIONAL REQUIREMENTS	ACTIVITIES/COMPETENCES
1. Asset Management Function	• Asset Register/Asset Valuation
2. Use of System and Interconnector Charging Function	• Use of System and Interconnector Charging Principles • Billing System
3. Ancillary Services Function	• Ancillary Services Procurement
4. Regulatory Relations Function	• Management of Regulatory Interfaces • Management of changes to Grid and Commercial Codes • Managing Regulatory Reporting Requirements
5. Balancing/Settlement/Trading Function	• Managing balancing and settlement processes and balancing trades • Balancing and Settlement System • Trading System
6. Data Registration Function	• Setting up and manage changes to system technical and asset database
7. Compliance Monitoring Function and Technical Audit	• Monitoring and testing compliance of TSO and all transmission system users with the Grid Codes
8. Connection Opportunities and Market Information	• Connection Opportunities to the system for generation and demand over the next 5-10 years • Dissemination of Market Information as directed by the Regulator and Market Rules • Managing UCTE Information Requirements
9. Asset Procurement	• Procurement systems • EU Competition Compliance • Country Competition Legislation
10. Financial Management	• Compliance with Financial Standards • Compliance with Audit Standards
11. Facilities and Tools	• SCADA, EMS, metering, data transfer and other operational facilities that include mechanisms

	enabling market operation • System Monitoring and Incident Analysis facilities • Ancillary Services delivery monitoring • Grid Code Compliance Monitoring and Testing facilities • Power System Analysis Software enabling a full range of studies
12. Staff	• Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy

Table 3. Essential Institutional Requirements and Competences enabling a TSO to operate in a Market Environment

INSTITUTIONAL REQUIREMENTS	ACTIVITIES/COMPETENCES
1. Electricity Market Legislation	• Energy Act • European Directives • Balancing and Settlement Code • Other Commercial Codes • Fuel Security Code • Civil Emergencies Legislation, Codes and Procedures
2. Regulatory Bodies	• Energy Act • Electricity Regulatory Organisation • Electricity Supply Regulations • European Directives • CEER
3. Licencing System	• Issuing of Licences • Licenced Energy Activities • Energy Act
4. Competition Legislation for Energy Sector	• Competition Act • European Directives
5. Government Agencies	• European Directives • Company Law • Audit Standards • Accountancy/Financial Standards • Competition Law • Monopolies and Mergers Authority
6. Government Agency Staff	• Ensuring adequate staff skills and training in understanding traditional utility management and technical competences • Training of staff in Market Operation (new skills)

In line with the above tables, the information obtained from the utilities throughout the project was analysed to identify the gaps, which need to be addressed by all the utilities in the SEE Region.

10 IMPLEMENTATION OF THE REGIONAL ELECTRICITY MARKET

10.1 INTRODUCTION

In the "The Athens Forum 3/4 June 2004 Discussion and Consultation Note" EC favours a two stage implementation approach namely the initial and the final REM by December 2005 and 2007 respectively. The EC considers the implementation of a day ahead market and regional markets and regional scheduling and dispatch to be matters that can be dealt with post 2007.

The basic principles for the Standard Market Design (the Full REM) are laid down in the CEER: "Position Paper on the SEE- SMD Basic Principles" produced following the 2nd meeting of the S.E. Europe Electricity Regulation Forum (the SEEER Forum) in Rome the 26-27 March 2003.

Initial REM identifies the minimum requirements to allow the jurisdictions to participate in a regional market. A full REM is assumed to be an implementation of the principles of the SMD, as outlined by CEER.

Initial REM envisages trading between generators and suppliers in different jurisdictions based on Bilateral Contracts. This means that it is necessary to:

- Set up Independent National Regulators be able to grant access to participants and oversee transparency, non-discrimination and tariffs;
- Establish Independent National TSOs able to operate the system securely within established security and quality of supply standards;
- Enable participants to sign contracts across jurisdictions;
- Set standards for registration of participants;
- Establish principles and means of appropriate data exchange;
- Agree formal dispute resolution procedure;
- Agree formal principles for scheduling interconnector transfers and ensure generation schedule of each jurisdiction allows physical transfers to occur; and
- Agree formal method of securing interconnector capacity for participants.

The full REM envisages the formation of a Day Ahead Market (DAM) and a South East Europe Market Operator (SEEMO) together with all the market mechanisms referred to in Sections 6 and 7.

10.2 TSO REQUIREMENTS FOR THE INITIAL AND FULL REM

Tables 1, 2 and 3 in Section 9 above defined the full TSO functional requirements. In the next two sections the functionalities that should be achieved as a minimum for the initial and full REM are marked in bold respectively.

TSO requirements considered necessary for the initial and full REM are summarised in Tables 5, 6 and 7 respectively for:

1. Basic duties and competences of the TSO;
2. TSO organisational requirements; and
3. Governmental and institutional requirements.

The analysis of the requirements of individual TSOs in all the jurisdictions covered by the REBIS project is given in Section 11, 12 and 13. The analysis includes estimates for the completion of each action for each of the utilities in the jurisdictions at especially the initial REM stage indicating the readiness of the utility to embrace operation as part of the REM. These time estimates assume that:

a. The governmental decisions to reorganise the industry are implemented and at least a TSO as a legal entity exists before the end of 2004;

b. Sufficient staff with the required expertise are made available to the TSO by each jurisdiction to oversee all the work necessary to deliver it to at least the initial REM;
c. The industry reorganisation to the initial and full REM progresses harmoniously as envisaged by EC as described in Section 10.1 above;
d. Necessary funds are authorised and made available to acquire the additional facilities necessary for the initial REM and then progressively onto full REM;
e. Funds to remove bottlenecks and constraints are also are authorised and made available to acquire the additional facilities necessary for the initial REM and then progressively onto full REM; and
f. Necessary external expertise and training is made available to progress into initial REM and then on to full REM.

Finally, the TSOs will be going through major organisational changes in technical, cultural and financial aspects of their operation. Given the current state of staff numbers and skills of even the best prepared of the utilities there is a very high volume of work requiring continuous attention of the highly skilled staff for at least the next three years. In addition, there are a lot of new skills to be learnt as well as the basic skills, which need to be enhanced. The insufficiency in government and institutional staff with adequate skills also means that there will be a high demand to draw such staff off the utilities. The efficiency with which these issues are managed will seriously affect the rate at which the initial and final REM is achieved. It is not always possible to apply external expertise to expedite the completion as the utility staff would need to take ownership and build up confidence through desktop exercises. Continued and full support of EKC and ZEKC is absolutely essential. The initial REM should be regarded as the stage where the utilities are building up the competences for the initial market operation and improving the staff skills for the full REM.

Table 5. Basic TSO Requirements and Associated Activities/Competences enabling a TSO to operate in the initial and full REM

TSO DUTIES	ACTIVITIES and COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES and COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Establish a fully documented System Planning process • Fully implement a sound System Operational Planning process • Establish fully documented Security and Quality of Supply Standards • Implement full Power System Analysis Capability • Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy) • Establish all planning and operational procedures • Fully implement UCTE Rules • Fully implement CEER and ETSO Guidelines • Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start)	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • Establish modern Construction Project Management

3. Enable Regulated Third Party Access	• Establish basic Grid Code (Connection Conditions) • Establish model Connection Agreements • Establish the principles of Use of System Charging Tariffs	• Implementation of the full Grid Code • Full implementation of Grid Code Compliance Processes and Monitoring • Connection Agreements with all transmission customers
4. Establish Grid Codes and compliance verification processes	• Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code) • Establish Compliance Verification and Testing (for new connections only)	• Implement Full Grid Code • Implement Compliance Verification and Testing for all connections
5. Set non-discriminatory connection and use of system charges	• Establish the principles of Use of System Charging Tariffs with the Regulator	• Fully implement and annually review Use of System Charging Tariffs with the Regulator
6. Set interconnection charges based on CEER and ETSO Guidelines	• Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines	• Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines
7. Facilitate Market Operation, Inter Country Trades and Manage Congestion	• Establish model Inter-country Trading Agreements • Establish Cross-Border Tariffs according to CEER and ETSO guidelines • Fully establish principles of Congestion Management process	• Manage congestion on a fully auditable basis • Fully implement all Commercial Codes
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• Become proficient in calculating Ancillary Services Requirements • Establish Ancillary Services Pricing Principles	• Implement Ancillary Services Pricing Principles • Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring
9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process • SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • System Operation to merit order and establishing interconnector transfers • Establish Operational Procedures • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) • Improve Congestion Management methods • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code • Management of Balancing and Settlement Information	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code • Focus on efficient congestion management • Full market based operation

10. Administer the settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities • Implement information Exchange Protocol with UCTE • Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • Sufficient metering and data collection facilities to enable market operation and billing	• Grid Code, Data Registration Code implemented in full • Market Information System implemented in full • Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the system for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

Table 6. Essential TSO Organisational Requirements and Associated Activities/Competences enabling a TSO to operate in the initial and full REM

ORGANISATIONAL REQUIREMENTS	ACTIVITIES and COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES and COMPETENCES FOR FULL REM
1. Asset Management Function	• Establish Asset Register/Asset Valuation Principles • Collect Asset information	• Fully operational Asset Register • Agreed valuation of assets
2. Use of System and Interconnector Charging Function	• Establish Use of System and Interconnector Charging Principles • Establish Billing System Principles	• Calculate Use of System and Interconnector Charges annually and obtain necessary approvals • Implement full Billing System
3. Ancillary Services Function	• Ancillary Services Procurement	• Ancillary Services Procurement to contracts and monitoring of delivery
4. Regulatory Relations Function	• Basic Establishment and Management of Regulatory Interfaces • Agree Regulatory reporting requirements	• Management of changes to Grid and Commercial Codes • Managing Regulatory Reporting Requirements
5. Balancing, Settlement and Trading Function	• Managing basic balancing and settlement processes and balancing trades	• Full Balancing and Settlement System • Trading System
6. Data	• Setting up the basic principles of and	• Fully operational system technical and

Registration Function	managing the system technical and asset database	asset database • Managing changes to the system technical and asset database
7. Compliance Monitoring Function and Technical Audit	• Start monitoring and testing compliance of TSO and all new transmission system users with the Grid Codes (i.e., initially new connections only)	• Full monitoring and testing compliance of TSO and all transmission system users with the Grid Code (all connections on a retrospective basis)
8. Connection Opportunities and Market Information	• Managing UCTE and Interconnector Information Requirements • Establish basic principles of Connection Opportunities statement with the Regulator • Establish basic principles of Market Information with the Regulator and the Market Participants	• Issue an annual statement giving Connection Opportunities to the system for generation and demand over the next 5-10 years • Disseminate of Market Information as directed by the Regulator and Market Rules
9. Asset Procurement	• Establish principles of Procurement systems • Move towards EU Competition Compliance • Start implementing Country Competition Legislation	• Fully operational Procurement systems • EU Competition Compliance fully implemented • Country Competition Legislation fully implemented
10. Financial Management	• Move towards Compliance with Financial Standards • Move towards Compliance with Audit Standards	• Full Compliance with Financial Standards • Full Compliance with Audit Standards
11. Facilities and Tools	• SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • Power System Analysis Software enabling a full range of system studies to be carried out	• Fully operational SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling full market operation • System Monitoring and Incident Analysis facilities • Ancillary Services delivery monitoring facilities • Grid Code Compliance Monitoring and Testing facilities
12. Staff	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy

Table 7. Essential Institutional Requirements and Associated Activities/Competences enabling a TSO to operate in the initial and full REM

INSTITUTIONAL REQUIREMENTS	ACTIVITIES and COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES and COMPETENCES FOR FULL REM
1. Electricity Market Legislation	• Energy Act • European Directives • Balancing and Settlement Code (basic rules for initial REM)	• Other Commercial Codes • Fuel Security Code • Civil Emergencies Legislation, Codes and Procedures
2. Regulatory Bodies	• Energy Act • Electricity Regulatory Organisation	• Electricity Supply Regulations • Regulatory Reporting

	• European Directives (compatibility for initial REM) • CEER	• Regulatory Incentives • Tariffs
3. Licencing System	• Definition of market participants • Energy Act	• Issuing of Licences • Licenced Energy Activities
4. Competition Legislation for Energy Sector	• Basic principles of Competition Act • European Directives (compatibility for initial REM)	• Competition Law
5. Government Agencies	• European Directives (compatibility for initial REM) • Company Law	• Full implementation of European Directives • Audit Standards • Accountancy/Financial Standards • Competition Law • Monopolies and Mergers Authority
6. Government Agency Staff	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy

11 STANDARDS AND PROCEDURES – UTILITY CAPABILITY AND PROGRESS

From the descriptions of documentation and methodologies given by the utilities in answer to the technical questionnaire, and follow-up discussions during the second technical visit, it is anticipated that the following advancements in standards and procedures will be needed by each utility as follows.

11.1 ALBANIA – KESH

KESH has a method of transmission voltage control, which is an effective standard but this needs to be formalised and written down. They state that they have primary control but do not give any further information. Further, they claim that they do not have secondary control, but are able to manage Area Control Error. Security of the system is claimed to be compliant with design/security standards but these are under preparation. Planning and operation of the system would appear to be much more by tradition than by written rules.

Standards

Planning standards are under preparation; there are no operational standards. There are also no Grid Code or Transmission Licence. Standards will need to be brought into line with these latter documents when they have been prepared. These will particularly need to concentrate on security, load frequency control, quality of supply and voltage management. The KESH statute is not a document that gives any indications of standards.

Planning Procedures/Rulebook

There are no planning procedures.

Operational Procedures/Rulebook

Operational rules are under preparation but these should be based on operational standards, which do not exist. It is, therefore, difficult to understand how a satisfactory set of operational rules can be achieved.

Discussion

Although some standards and procedures are in preparation their scope appears to be limited and significantly more work need to be done in this field. Urgent attention needs to be paid to the Grid Code and the Transmission Licence, and complete standards and rules cannot be achieved until these former documents are in place.

11.2 BOSNIA AND HERZEGOVINA – EPBiH, EPHZHB, ERS

The assumption must be made that ZEKC will form the single TSO and that the best parts of the current standards and rules of each utility can be combined into a single set of standards and procedures. A draft Grid Code has been prepared by KEMA Consulting and contains some information on standards to which the transmission system should be planned and operated.

Standards

A definition of what constitutes the transmission system needs to be developed.

The (n-1) standard is cited by all three utilities. This is interpreted by the utilities as all circuits in pre-fault for long term studies, but the system as it is for operational studies. A planning standard, that clearly defines both operational and planning criteria to meet the (n-1) standard, needs to be developed.

Primary and secondary frequency control for all utilities appear to be carried out according to UCTE rules and ERS, particularly, provides information on the performance differences between thermal and hydro plant for primary response. However, the methodology of achieving both primary and secondary response needs to be included in a standard, particularly relating to plant performance requirements and Area Control Error performance targets.

Transmission voltages are optimized by classical methods, mainly by instruction of generator MVAr output. There appears to be no formal procedure for assessing MVAr reserves. There does not seem to be a standard for maximum and minimum voltages and, voltage steps, at each voltage level, or target voltages at the customer interfaces. These need to be codified and consistent with any values specified in the Grid Code or the Transmission Licence.

There are specific levels for emergency low frequency demand disconnection. Although, for the lower levels of under frequency demand disconnection the values are consistent, the first stage frequency settings will need to be brought into line. There do not seem to be any minimum standards for customer connection arrangements (either generator or consumer). These need to be described and be consistent with any values specified in the Grid Code or the Transmission Licence.

Planning Procedures/Rulebook

Both EPBiH and EPHZHB state that the documentation is very comprehensive, but is in local language and not available outside the company without management consent.

Whatever the contents of these documents it is likely they will need to be harmonised, updated to include whatever is within ERS documentation, and brought in line with market requirements.

Operational Procedures/Rulebook

The same remarks apply to this section.

Discussion

The basis on which a set of standards and procedures can be formulated is variable between the three companies. What is available needs to be harmonised and enhanced to conform to Grid Code and Transmission Licence requirements.

11.3 CROATIA – HEP

Primary and secondary frequency control is under the control of the system operator who defines the generators on frequency control. The system is operated according to the (n-1) security criterion.

Standards

A definition of what constitutes the transmission system needs to be developed. This has been unnecessary up to now because of the vertically integrated utility, but with the split of generation and, probably thereafter, distribution it becomes necessary.

Secured contingencies are simply specified as (n-1) in accordance with UCTE recommendations and the grid code. This definition needs to be amplified so that the system is planned to facilitate (n-1) operation, and to allow for maintenance outages of generation and transmission circuits. Statements made by HEP during the first technical visit indicate that loss of some 400kV circuits will overload the 220kV system. Consideration needs to be given over how this can be accommodated within the standard of if the aim is to bring the system to a true (n-1) standard.

Primary and secondary frequency control are carried out according to UCTE rules; these need to be included in a company standard, particularly relating to plant performance requirements and Area Control Error performance targets.

Transmission voltages are managed by classical methods. However, there does not seem to be a standard for maximum and minimum voltages and, voltage steps, at each voltage level, or target voltages at the customer interfaces. These need to be codified and consistent with any values specified in the Grid Code or the Transmission Licence.

There do not seem to be any recommendations on the amount of load that can be shed during a secured contingency or any minimum standards for customer connection arrangements (either generator or consumer). These need to be described and be consistent with any values specified in the Grid Code or the Transmission Licence.

Planning Procedures/Rulebook

HEP state that planning procedures are described in the grid code. It is unlikely that these will be in sufficient detail so will need to be written.

Operational Procedures/Rulebook

There is considerable documentation for operation of the system. This will need to be enhanced to take account of the new requirements of the electricity market.

Discussion

Planning of the transmission system places reliance on the rules as applied the UCTE handbook and the Grid Code. While these give overall requirements they need to be interpreted in relation to the transmission system and the generation and users connected to it. There are a number of operational rules that can be enhanced to take account of the new market requirements.

11.4 FYR MACEDONIA – ESM

ESM are well advanced in operating their system against a set of rules and standards. Currently there is no Grid Code or Transmission Licence, but when these are available the rules and standards will need to be aligned with them. It is to be hoped that when these statutory documents are drafted they will take into account, as far as is possible, the current regulations and practices that are applied.

Standards

A definition of what constitutes the transmission system needs to be developed.

What are deemed to be secured contingencies for both planning and operation of the system are, clearly, understood and go further than simple reliance on an (n-1) criterion, utilising various combinations of outrages to maintain security for maintenance conditions. The way in which this has been applied has been thought out in depth and can be utilised to create an effective standard.

Primary and secondary frequency control are carried out according to UCTE rules and plant performance and characteristics are understood and utilised to achieve optimum control. It is surprising, therefore, that ACE performance is not particularly good. However, the practices can be utilized to create an effective standard.

Transmission voltages are obviously well managed by classical methods. There is a standard for maximum and minimum voltages at each voltage level. This could be enhanced by stipulating maximum voltage step changes and target voltages at the customer interface. These need to be codified and consistent with any values specified in the Grid Code or the Transmission Licence.

Load shedding under emergency under frequency conditions is limited to some large consumers, although load shedding at distribution level is being installed. The quantities and levels at which this is done need to be consistent with other utilities in the area and codified within a standard.

It is noted that standards are generally defined in the Law on Energy and any set of standards developed must be consistent with this.

Planning Procedures/Rulebook

It is noted that all activities in power sector are based on the standards and procedures generally defined in the Law on Energy, published in Official Gazette of Republic of Macedonia. While this may be a good basis for planning procedures it is unlikely to contain the detail that is required to develop a full set. It is also noted that, apparently, technical criteria are defined at the beginning of each study, particularly since it is stated that technical criteria and planning procedure cannot be found in written format in formal documentation. This may lead to inconsistency in application of standards and there is, consequently a requirement to develop a set of procedures.

Operational procedures/rulebook

It is noted that operation of the transmission system is regulated also by Regulations where operation procedures and competences in control of the system have been worked out. It is not clear whether these are in written form but there appears to be a good basis for developing a comprehensive set of operational procedures. However, it is likely that additional rules/procedures will be required that deal with grid code compliance, reporting to the regulator and other factors that will be introduced as a result of the new electricity market.

Discussion

ESM have a good basis within their practices and the Law on Energy on which to go forward and create a set of standards and procedures which will be appropriate for the new electricity market. However, these need to be brought in line with the Grid Code and the Transmission Licence and enhanced to take account of factors that do not occur in a vertically integrated utility.

11.5 MONTENEGRO – EPCG

Both the technical visits demonstrated competent operating practises, and it is probable that many procedures can be written if custom and practise are codified.

Standards

A definition of what constitutes the transmission system needs to be developed. This has been unnecessary up to now because of the vertically integrated utility.

Secured contingencies for operation rely on an (n-1) criterion which is defined as the network as it is on the day. This needs to be codified into a standard consistent with any requirements of the Grid Code and Transmission Licence.

Primary and secondary frequency control are carried out 'according to UCTE rules' but these need to be included in a company standard, particularly relating to plant performance requirements and Area Control Error performance targets. Nevertheless ACE is managed within strict limits and performance has been better than for surrounding utilities. It should not be difficult to translate practice in to a standard.

Transmission voltages are by classical methods but precisely how this is done is unclear. There does not seem to be a standard for maximum and minimum voltages and, voltage steps, at each voltage level, or target voltages at the customer interfaces. These need to be codified and consistent with any values specified in the Grid Code or the Transmission Licence.

There is no automatic under frequency load shedding but it is applied manually under emergency conditions. There need to be automatically facilities consistent with other utilities in the area and frequency levels and quantities specified within a standard.

Planning Procedures/Rulebook

From the information supplied there seem to be very few documents on which planning procedures could be built. This will mean the formulation of a new set of procedures based on current planning practises and the standards that are implemented.

Operational Procedures/Rulebook

As with planning procedures, from the information supplied there seem to be very few documents on which operational procedures could be built. This will mean the formulation of a new set of procedures based on current operational practises and the standards that are implemented.

Discussion

EPCG do not appear to have a particularly good basis on which to go forward and create a set of standards and procedures, which will be appropriate for the new electricity market. It is believed that both standards and procedures will need to be written from scratch, but there may some basis of practices on which they can be based.

11.6 SERBIA – EPS

EPS has well developed methods of voltage control, and primary and secondary frequency control, and the Rule Book on Electrical Power System Operation and Dispatch Control which contains details power system operational planning and control which must encompass these methods. The system is designed according to “security standards” which provide a detailed definition of the UCTE (n-1) criterion in excess of the somewhat vague provision in the UCTE Rulebook. There are no standards covering transmission system planning although regular studies are carried out for short term and long term planning.

Measures for emergency conditions are well covered by the emergency and under frequency load shedding plans.

Therefore, the following are required within transmission standards and procedures/rulebooks:

Standards

A definition of what constitutes the transmission system needs to be developed. This has been unnecessary up to now because of the vertically integrated utility.

What are deemed to be secured contingencies for both planning and operation of the system are, clearly, understood but these need to be codified into a standard consistent with any requirements of the Grid Code and Transmission Licence; also by using parts of the rulebook that deals with operational control, and custom and practise for planning studies.

Primary and secondary frequency control are carried out according to UCTE rules but these need to be included in a company standard, particularly relating to plant performance requirements and Area Control Error performance targets.

Transmission voltages are obviously well managed by classical methods. However, there does not seem to be a standard for maximum and minimum voltages and, voltage steps, at each voltage level, or target voltages at the customer interfaces. These need to be codified and consistent with any values specified in the Grid Code or the Transmission Licence.

There do not seem to be any recommendations on the amount of load that can be shed during a secured contingency or any minimum standards for customer connection arrangements (either generator or consumer). These need to be described and be consistent with any values specified in the Grid Code or the Transmission Licence.

Planning Procedures/Rulebook

The rulebook on power system operation includes data preparation and preparation of electrical energy balance which will include short term demand forecasts. However, long demand forecasting and outage planning seem to rely on regular studies and criteria described in one of the reports. These need to be codified.

Under a market structure applications to connect to the transmission system will need to be handled in a structured way, and the utility will need to publish, annually, a report on the most appropriate places for connection. Procedures for both of these activities need to be written.

The UCTE rulebook is very specific on the need for accurate measurements in a number of areas. While this latter document is an operational document the creation of accurate measurement capability and database handling is a planning activity and needs to be codified within the planning procedures.

The rule book for evaluation of power plants participation in load frequency control is as a prepared draft on technical solutions. This, in part, covers confirmation of plant performance but needs to be enhanced to cover the provision of all ancillary services and assurances that they can be delivered when required.

Basically, although there are some issues dealt with within the rulebooks, the planning procedures/rulebook needs to be written.

Operational Procedures/Rulebook

Many of the required procedures are already dealt with in the Rulebooks on electric power system operation and dispatch control, and under frequency and load shedding plans. These include demand estimation, outage planning, management of reserves and ancillary services, load frequency control and voltage control and management. Some of these may need to be enhanced for a market structure. Safety co-ordination and contingency planning and restoration are also dealt with in the rulebook for execution of works and the rulebook on partial or total blackout respectively. Some may need to be enhanced.

How to achieve Grid Code compliance, and reporting to the regulator, need to be included as new items.

Discussion

EPS have a very good basis within their practices and their rulebooks on which to go forward and create a set of standards and procedures, which will be appropriate for the new electricity market. However, these need to be brought in line with the Grid Code and the Transmission Licence and enhanced to take account of factors that do not occur in a vertically integrated utility. More work needs to be done on planning than operational aspects.

11.7 UNMIK – KEK

Answers to the questionnaire have been limited and documentation is in the process of being written.

Standards

The need for a definition of what constitutes the transmission system may be less necessary than for other utilities since it is very small, with a single major substation. Nevertheless, it will be necessary create a standard for voltage control since Kosovo is a major bussing point and, therefore, particularly important to the integrity of the transmission system in the region.

The system is operated to (n-1) security, but a precise definition of what this means is required in the standard. It is noted that the 110kV system is not secure to this criterion; a decision needs to be taken on whether this is acceptable and should be included within the operational standard or whether the planning standard should be written to preclude this problem, with the consequent changes in investment requirements.

Primary and secondary frequency control is carried out by agreement by EPS. Given that KEK has effectively a single generating station this is probably sensible but it needs to be codified.

Under frequency load shedding is available at a number of substations. These need to be detailed within a standard.

Planning Procedures/Rulebook

Since these are under construction it is not possible to comment on their suitability to meet standards. They must, obviously be appropriate to meet statutory requirements, but, because of the limited nature of the system, may be less comprehensive than for other utilities.

Operational Procedures/Rulebook

Similar remarks apply as for the planning procedures.

Discussion

KEK are currently creating standards and procedures. These need to be consistent with statutory documentation.

12 ADDITIONAL FACTORS

12.1 ACCURACY OF MEASUREMENTS

Measurements are required within a defined level of accuracy in order to be able to:

- operate a transmission system;
- manage and account for transfers across inteconnectors;
- manage and account for generation output and supply;
- manage and account for ancillary services;
- enable, initiate and control automatic actions;
- provide sufficient and reliable information to allow operators to manage the transmission system and make correct and appropriate decisions; and
- provide sufficient and reliable information for input to system studies both off-line and on-line if these facilities are available.

The UCTE Handbook does not cover all of these issues but is specific in the areas of frequency measurement, power measurement, transmission power deviations, and electricity metering. The transmission standards are high level documents that specify the required performance of the transmission system, and are not designed to contain the sort of detail that is required here. However, in order that the required performance can be achieved the accuracy of measurement is of paramount importance and this is illustrated by the values given in the UCTE Handbook where it is specific.

Therefore, such detail needs to be contained within the rulebook/procedures so that other procedures and the standards are complied with. The detail will be commensurate with the requirements to plan and operate the transmission system within the standards and include plant connected to it, e.g. generation and supply.

12.2 INFORMATION EXCHANGE

In order that utilities can plan and operate their systems in conjunction with neighbouring utilities there is a need for exchange of information in both planning and operational time scales. The UCTE rulebook is very specific about the requirements. TSOs are responsible for maintaining continuously available communication with their neighbouring TSOs, and each TSO must always have available reliable power system data for operational planning and real time operation.

Each TSO must provides an adequate, reliable, secure, fast and highly available communications infrastructure to assure permanent exchange of information between TSOs. Where possible, the telecommunication facilities should have a measure of redundancy and be diversely routed. In order to face any contingency in telecommunication facilities and to assure maintaining liaison between operators during emergency conditions, any route needs to be backed up by others.

Power System Computation

TSOs need to provide to each other, on a yearly basis, a provisional data-set including network, generation, load and exchange programmes for the preparation of a reference case system model. These data sets need to include information on development of the system, be for different seasons of the year, and include congestion information. Details of requirements are given within the UCTE operational handbook.

Outage Planning

Both transmission and generation plant will be taken out of service, periodically, for maintenance and will also, more infrequently, be taken out of service to enable new connections and system restructuring to take place. These outages will affect the transmission system of the utility itself and those of neighbouring utilities. Further, generation outages, may affect the way the transmission system has to be operated. It is, therefore, essential that details of these outages are exchanged in all time scales and agreed between affected parties.

The UCTE Handbook specifies a number of requirements, and that each TSO exchanges data bilaterally or together for planning and studies, when necessary, for example:

- The results of power system studies pertinent to operation;
- Outage scheduling of transmission elements at different time intervals: year ahead and more frequently when appropriate;
- Assumptions of pattern of generation for the power plants having the main influence on system operation, when appropriate at boundary;
- Aggregated cross-border exchange programmes between control areas and countries;
- Cross-border transfer; and
- Changes in operating conditions and limits.

These requirements specifically refer to operation of the system, and do not include procedures for exchange of information between utilities and relevant power plants. Similar information will be required for long term planning studies.

Exchange Programmes

Co-ordination and information exchange mechanisms need to be in place between the utilities to ensure the security of the networks in normal and contingency conditions and in the context of congestion management.

TSOs must continuously communicate for reasons of security of power network operation, for planning and for any related data needed by the network users. Data transfer and data processing systems must ensure that these centres are continuously supplied with up-to the minute information on the operating condition of the power stations and of the switching status in the transmission network, as well as on the condition of the transformer and the compensation equipment. Real time values of active and reactive power and system voltages need to be available and adequate SCADA systems are required to achieve this which will include back up systems.

With respect to telecommunication equipment, the transfer of important information to the dispatching centres, and between them, and, therefore, must have certain characteristics:

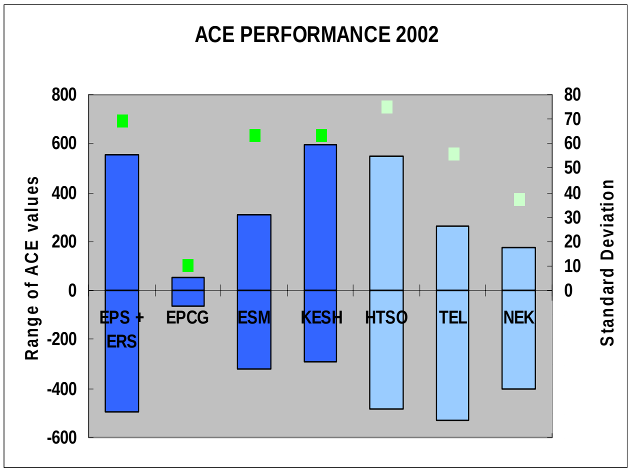
- There must be a sufficient number of guaranteed routes with back-ups;
- Routes are used for both data transfer and remote switching and instruction capability;
- The electricity supply to dispatching centres is backed up on a non-interruptable basis; and
- TSOs can manage continuous available communications even during a general loss of communication facilities.

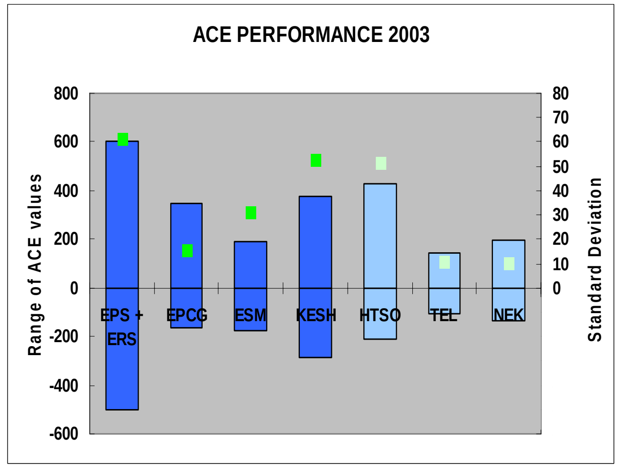
Conclusion

A number of issues have been highlighted here which have not been considered either explicitly or in detail in previous sections of this report. Nevertheless, there need to be recognised methodologies over how these requirements are achieved and these need to be included within the appropriate planning or operational procedure.

12.3 COMPARISON OF ACE PERFORMANCE

Unfortunately, the UCTE Handbook, whist defining Area Control Error and the methodology for control, provides no guidance on preferred performance apart from stating that ACE needs to be controlled to zero on a continuous basis. Instantaneously, it can and will depart from zero, but any long term value other than zero means that a utility has either imported or exported energy contrary to scheduled transfers. The EKC Annual Reports for 2002 and 2003 supply statistical information on ACE performance for all the JIEL block utilities, and this is reproduced in graphical form below:





Of the utilities considered in this report EPCG and ESM perform the best, with other utilities having a very wide range of ACE values. However, between 2002 and 2003 most utilities have improved their performance with the exception of EPCG and EPS. This does demonstrate the need for agreed target values between the utilities so that some utilities are not providing additional reserve to make up for the poor performance of others.

12.4 DEFINITION OF FIRM CAPACITY

The usage of the term firm capacity for generation leads to considerable misunderstandings. It is important that this is clarified, and that a common understanding is achieved within all utilities as it affects the need for generation investment and planning of the system on a long term and operational basis. Unfortunately, the UCTE Handbook contains no definition of generation firm capacity nor guidance on how the availability of generation should be considered during the various stages of planning studies.

Theoretically, total generation that is available to satisfy demand is the sum of all the rated generator net output capabilities on the system. However, at any one time this will not be achievable because:

- Generators may be derated because of plant problems;
- Generating plant will be maintained and, therefore, taken out of service; although, when running, this plant may give full output it will not be available for 8760 hours in a year. Its effective output is, therefore, reduced for the purpose of planning the system both in long term planning and operational time scales.
- Generators that are scheduled may not be available for dispatch due to breakdowns; and
- In the case of hydro generators, reservoir levels.

Therefore, generator firm capacity is not the installed capacity, which many utilities take it to be, but significantly less than that amount dependent on the time scale in which the planning study is carried out.

Where a utility has a large number of each type of generating plant, for planning purposes it may be sufficient to use an average availability for each type of plant. However, in the region under consideration, many utilities have very limited generation and a different method of accounting for plant availability will need to be used based on whole set modelling rather than averaged values.

Firm capacity needs to be defined within each utility's procedures so that planning of each system is carried out on a common basis.

12.5 MVAr FORECASTING AND REACTIVE RESERVES

No utilities carry out MVAr demand forecasting. Although this has not traditionally been done, it has been found that as communities become more affluent MVAr demand becomes higher and that fixed relationships between MVAr and MW demand no longer apply. Unless there is a direct and proved consistent relationship between MW and MVAr some element of MVAr forecasting should be undertaken by all utilities to ensure that reactive reserves will be sufficient for current conditions and in the future.

12.6 CHECKLISTS

Although standards and procedures are, in some cases, the formalised versions of what is already within rule books or carried out by custom and practice, it is appropriate to understand the requirements for how and where this formalization can take place. Check lists are provided here to allow this process to take place.

Custom and practice

1. Can it be written down?
2. Is it compatible with any existing rulebooks, standards or procedures?
3. How will it be converted into Standards and Procedures?
4. Is it compatible with the Licence, Grid Code and other Statutory documents?
5. Is it compatible with the rules of the UCTE and other organisations?
6. Does it cover all the requirements of the Licence, Grid Code and other Statutory documents
7. Does it cover all the rules of the UCTE and other organisations?
8. If there is a conflict how will these be resolved?
9. Is it agreed by the Regulator?
10. What steps will be taken to convert it to written format, adequacy and compatibility?
11. What time scales are involved?

Existing Rulebooks, Standards and Procedures

1. Are they compatible with the Licence, Grid Code and other Statutory documents?
2. Are they compatible with the rules of the UCTE and other organisations?
3. Do they cover all the requirements of the Licence, Grid Code and other Statutory documents
4. Do they cover all the rules of the UCTE and other organisations?
5. Are there any conflicts and how will these be resolved?
6. Are they agreed by the Regulator?
7. What steps will be taken ensure enhancement, adequacy and compatibility?
8. What time scales are involved?

13 THE TSO FUNCTIONAL REQUIREMENTS IN A MARKET ENVIRONMENT - ANALYSIS OF THE NEEDS OF JURISDICTIONS FOR THE INITIAL AND FULL REM

13.1 ALBANIA (KESH)

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities: • Transmission system boundaries with the generation and distribution systems are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. **Full establishment of the defined boundaries in legal terms required for initial REM. Otherwise ready for initial REM.**	• Implement full Asset Register: • Establish an Asset Replacement, Refurbishment and Investment Policy • There is no discernible fully documented asset replacement and investment strategy as yet. There is however a Transmission Master Plan prepared by DECON-EDF-LDK in January 2003 dealing with transmission investments for the 2002-2015 period. **Full Asset Register and Asset Replacement policy required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Database of historical MW load data is kept from hourly meter readings. There is no weather related data. There is however, a long term demand forecast prepared by DECON-EDF-LDK in January 2003 dealing with the forecast for the 2002-2015 period. The utility needs to develop its own load forecasting process within the next two years for initial market operation. This should include recording of MW, Mvar and weather data. **A reliable short term demand forecasting process needs to be established for initial REM. Databases for the longer term forecast need to be established to undertake the necessary work for full REM.** Establish a fully documented System Planning process • Planning Standards are reported to be under preparation. No analytical tools are reported to be utilised in planning and operational timescales. KESH reports that system studies appear to be confined to system maximum demand and maximum import conditions. **For initial REM the planning standards need to be completed and a simple planning process needs to be put in place to enable some annual studies to be made by the**	• Optimised and efficient system design and operation **Full long and short term demand forecast process needs to be implemented for full REM. Estimated completion end 2008. Planning standards and planning process needs to be implemented. Estimated completion end 2008.** • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as

	utility staff. Estimated completion mid 2006. • Fully implement a sound System Operational Planning process • Whilst an operational planning and outage coordination process appears to be in place with clearly defined responsibilities, the studies are mainly manual based upon experience and some use of the PSS/E package is occasionally made. **The operational planning process needs to be well established with full system steady state and dynamic studies being carried out using the PSS/E package for initial REM.** • Establish fully documented Security and Quality of Supply Standards • The (n-1) criterion is well understood but not fully recorded as it is difficult to achieve in practice due to lack of transmission facilities. Quality of Supply criteria is ignored as it is difficult to achieve supply to a standard with inadequate transmission facilities. **Security and Quality of Supply Standards should be set down for initial REM to establish the fundamental basis of transmission investment and take ownership.** • Implement full Power System Analysis Capability • The utility has its own home grown software and the PSS/E package but it is not fully capable of using these packages effectively on a daily basis in the planning and operational planning processes. **Planning and Operational Planning staff should be fully trained to at least run regular load flow studies for initial REM on the condition that EKC undertakes the regional stability studies.** • Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy) **The utility must get into the practice of aiming to operate the system fully to Security and Quality of Supply Standards recording the actions taken which will in turn justify the investment requirements in the run up and at the initial REM stage.** • Establish all planning and operational procedures • At present there are no recorded planning and operational procedures. **The utility needs to establish a culture of planning and operational procedures and compliance with these procedures. For initial REM as a minimum these may be procedures related only to the basics for internal utility and interconnector operation.** • Fully implement UCTE Rules • The utility is well aware of the UCTE rules. • Fully implement CEER and ETSO Guidelines • The utility is well aware of the CEER and ETSO guidelines. • Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start)	interconnectors **Review Transmission Master Plan prepared by DECON-EDF-LDK in January 2003 in line with other regional developments prior to full REM to focus investments.** **Planning and Operational staff fully capable of and carrying out load flow and stability studies on a regular basis by full REM.** • Monitor system operational efficiency • Establish modern Maintenance Practices • There is little opportunity to take outages so the development of adequate maintenance practices suffers. This will only improve in time as system becomes more adequate. **The maintenance practices would need to be brought up to date progressively up to initial and then final market operation.** • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent contractors. **However, up to date practices need to be put in place for full REM.** **The Security and Quality of Supply Standards should be made uniform across the region and UCTE within the next two years to achieve a single application procedure across**

<table>
<tr><td></td><td>The utility complies with UCTE rules for frequency control however; it is currently not fully capable to establish its Ancillary Services requirements especially reactive power reserve for voltage control.
<u>The reactive power and voltage management processes need to be fully established for initial market operation.</u></td><td><u>the REBIS as well as all UCTE participants.</u>

<u>The utility needs to establish a culture of operational procedures and compliance with these procedures. A full set of procedures and compliance monitoring processes need to be put in place for full REM.</u></td></tr>
<tr><td>3. Enable Regulated Third Party Access</td><td><u>Establish basic Grid Code (Connection Conditions)</u>
There is no Grid Code. Its preparation awaiting the EDF donation.
<u>The bulk of the Grid Code is required for the initial REM to introduce necessary planning, operational planning and operational disciplines in preparation for full REM. The existing drafts of Grid Codes in some jurisdictions could be used to produce a template for compatible Grid Codes.</u>
<u>Preparation of the principles for the Grid Code Compliance Process should be progressed together with the development of the Grid Code.</u>
<u>Establish model Connection Agreements</u>
There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation.
<u>Establish template for model Connection Agreements suitable for different types of customers for initial REM.</u>
<u>Establish the principles of Use of System Charging Tariffs</u>
There are no Use of System Charging Tariffs in place.
<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u></td><td><u>Implementation of the full Grid Code</u>
<u>Full implementation of Grid Code Compliance Processes and Monitoring</u>
<u>Connection Agreements with all transmission customers</u></td></tr>
<tr><td>4. Establish Grid Codes and compliance verification processes</td><td><u>Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code)</u>
There is no Grid Code. Its preparation awaiting the EDF donation.
<u>See comments in TSO Duty No. 3 above.</u>
<u>Establish Compliance Verification and Testing (for new connections only)</u>
<u>Establish basic compliance verification and testing process for applicable to new connections for the initial REM.</u></td><td><u>Implement Full Grid Code</u>
<u>Implement Compliance Verification and Testing for all connections</u></td></tr>
<tr><td>5. Set non-discriminatory connection and use of system charges</td><td><u>Establish the principles of Use of System Charging Tariffs with the Regulator</u>
<u>See comments in TSO Duty No. 3 above.</u></td><td><u>Fully implement and annually review Use of System Charging Tariffs with the Regulator</u></td></tr>
</table>

6. Set interconnection charges based on CEER and ETSO Guidelines	• Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines • The Interconnection charging tariffs are awaiting the reorganisation of the industry and establishment of adequate generation capacity. • At present EKC assigns the interconnector transfer limits. **Establishment of Interconnection Charging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.**	• Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines
7. Facilitate Market Operation, Inter-Country Trades and Manage Congestion	• Establish model Inter-Country Trading Agreements • There are currently trading agreements with Greece, Kosovo and Montenegro these can continue into initial market operation taking account of new rules. • There are no Commercial Codes or settlement rules for initial market operation. **Establishment of Inter-Country Trading Agreements is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.** • Establish Cross-Border Tariffs according to CEER and ETSO guidelines • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines for initial market operation. **See comments in TSO Duty No. 6 above.** • Fully establish principles of Congestion Management process • Congestion Management is currently done manually based upon operator experience and frequently load shedding is used to enable outages to be taken. **Establish principles of congestion management based upon load flow studies made for operational planning compliant with Security and Quality of Supply Standards for the initial REM. Record constraints and remedies providing signals for investment and operational measures.**	• Manage congestion on a fully auditable basis • Fully implement all Commercial Codes
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• Become proficient in calculating Ancillary Services Requirements • The utility complies with UCTE rules for frequency control however; it is currently not fully capable to establish its Ancillary Services requirements especially reactive power reserve for voltage control. **See comments in TSO Duty No. 2 above.** • Establish Ancillary Services Pricing Principles • There are no Ancillary Services Pricing Principles, Contacts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. **See comments in TSO Duty No. 2 above.**	• Implement Ancillary Services Pricing Principles • Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring
9. 9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process **A reliable short term demand forecasting process needs to be established for initial REM.**	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market

	• SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • Current National Control Centre is obsolete. There is a mini SCADA system under consideration on an urgent basis with a future full SCADA/EMS system. The functional specifications have been prepared. This could provide at least a basic level of monitoring facilities for System Operation, Ancillary Services and System Incident Investigation. **The installation of the mini SCADA/EMS system is a priority for the initial REM.** • System Operation to merit order and establishing interconnector transfers • Present merit order operation is based upon verbal information and minimal manual analysis based upon experience with a least cost objective. Interconnector transfers are determined by EKC. EKC carries out the overall interconnection transfer security coordination with the UCTE. **Establish at least a simple merit order operation based on a spreadsheet backed up by load flow studies and EKC help for interconnector transfers for initial REM.** Establish Operational Procedures **See comments in TSO Duty No. 2 above.** • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) **See comments in TSO Duty No. 2 above.** • Improve Congestion Management methods **See comments in TSO Duty No. 7 above.** • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code **See comments in TSO Duty No. 3 above.** • Management of Balancing and Settlement Information • Management of Balancing and Settlement Information can be handled by simple spreadsheets for initial market operation. **Establish simple spreadsheet for Balancing and Settlement for initial REM.**	operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code • Focus on efficient congestion management • Full market based operation
10. Administer the settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **See comments in TSO Duty No. 9 above.**	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes
11. Facilitate information exchange	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities	• Grid Code, Data Registration Code implemented in full • Market Information System

between dispatch centers and communicate with the market participants	• Implement information Exchange Protocol with UCTE • Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • At least a basic data registration and data exchange process needs to be in place to enable exchange of data between industry entities, with interconnected utilities, EKC and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** Sufficient metering and data collection facilities to enable market operation and billing • Metering facilities dated and not sufficiently accurate. No remote data collection facilities. Some assumptions on metering necessary for facilitating initial REM. **At least basic metering facilities compatible with the other market participants necessary for initial REM.**	implemented in full • Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the system for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be a shortage of qualified staff, staff skills and training. These are essential for successful reform of utility and market operation. **See comments in TSO Duty No. 2 above. Staff recruitment and training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

13.2 BOSNIA AND HERZEGOVINA (EPBiH, EPHZHB and EPRS combined)

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities • EPBiH: Transmission system boundaries with distribution are well defined. However, some generation boundaries are part owned and need to be contractually clarified. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. • EPRS: Transmission system boundaries with generation and distribution are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. • EPHZHB: Transmission system boundaries with generation and distribution is yet to be fully defined. It is felt that the Law establishing the BiH transmission company will clarify this and enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. **Full establishment of the defined boundaries in legal terms required for initial REM. Otherwise ready for initial REM.**	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy • The principles and priorities for asset replacement and investment strategy are well established. **Full Asset Register and Asset Replacement policy required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • In all three utilities Load Forecasting is carried out based upon home grown software yielding better results than commercial software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **Present load forecasting methods adequate for initial REM. Mvar forecast data collection should be immediately undertaken by all three utilities to enable development for full REM.** • Establish a fully documented System Planning process • In all three utilities Planning Standards appear to be well established. Planning studies are carried out by each utility for its own area and ZEKC carries out studies for the whole of BiH. **System Planning Process well established in all three utilities and ready for initial REM. Start training staff in system stability studies for full REM.** • Fully implement a sound System Operational Planning process • There is a well established operational planning and outage coordination process in place. Studies are carried out by all three utilities for the own areas and full BiH coordination is carried out by ZEKC. **Operational Planning Process well established in all three utilities and ready for initial REM.**	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • The utility appears to have adequate maintenance practices and procedures in place. • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent

	• <u>Establish fully documented Security and Quality of Supply Standards</u> • The (n-1) criterion is well understood and reasonably recorded by all three utilities. Attention to application of Quality of Supply criteria is also paid through attempts to implement Euronorms and transformer loading studies. **<u>All three utilities should Review Security and Quality of Supply criteria for incorporation into the Grid Code for initial REM.</u>** <u>Implement full Power System Analysis Capability</u> • All three utilities have some home grown software and the PSS/E package. They reasonably capable of using these packages effectively on a daily basis in the planning and operational planning processes. **<u>All three utilities ready for initial REM and further training required for full REM should commence immediately.</u>** • <u>Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy)</u> **<u>All three utilities ready for initial REM.</u>** • <u>Establish all planning and operational procedures</u> **<u>All three utilities need to review and re-establish planning and operational procedures and compliance with these procedures for initial REM.</u>** • <u>Fully implement UCTE Rules</u> • All three utilities_are well aware of the UCTE rules as well as CEER and ETSO guidelines. • <u>Fully implement CEER and ETSO Guidelines</u> • All three utilities are well aware of the UCTE rules as well as CEER and ETSO guidelines. • <u>Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start)</u> • All three utilities_comply with UCTE rules for frequency control and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not calculated although the utility is fully capable to do so when needed. **<u>The reactive power and voltage management processes need to be improved in all three utilities for initial market operation.</u>**	contractors. **<u>Review the load forecasting process for Mvar forecast and accuracy in 2007 or 2008.</u>** **<u>The Security and Quality of Supply Standards should be made uniform across the region and UCTE within the next two years to achieve a single application procedure.</u>** • The PSS/E software package is well recognised and staff appears to be adequately trained in its use with regular refresher training required for initial market operation. • The reactive power and voltage management processes need to be improved over the next two years for initial market operation.
3. Enable Regulated Third Party Access	• <u>Establish basic Grid Code (Connection Conditions)</u> • There is a draft BiH Grid Code (27.11.2002) sponsored by DFID, UK and prepared by KEMA Consulting. **<u>The bulk of the Grid Code is required for the initial REM to introduce necessary planning, operational planning and operational disciplines in preparation for full REM. The existing draft of Grid Code needs a little further work for completion by</u>**	• <u>Implementation of the full Grid Code</u> • <u>Full implementation of Grid Code Compliance Processes and Monitoring</u> • <u>Connection Agreements with all</u>

	mid 2005. This could also be used to produce a template for compatible Grid Codes for other jurisdictions. • Although there is a draft BiH Grid Code, as yet there are no technical compliance processes in place. **Preparation of the principles for the Grid Code Compliance Process should be progressed together with the development of the Grid Code.** • Establish model Connection Agreements • There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation. **Establish template for model Connection Agreements suitable for different types of customers for initial REM. Estimated completion end 2006.** • Establish the principles of Use of System Charging Tariffs • There are no Use of System Charging Tariffs in place. **Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.**	transmission customers
4. Establish Grid Codes and compliance verification processes	• Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code) **See comments in TSO Duty No. 3 above.** • Establish Compliance Verification and Testing (for new connections only) • There is a draft BiH Grid Code (27.11.2002) sponsored by DFID, UK and prepared by KEMA Consulting however, there are no technical compliance processes in place. **Establish basic compliance verification and testing process for applicable to new connections for the initial REM.**	• Implement Full Grid Code • Implement Compliance Verification and Testing for all connections
5. Set non-discriminatory connection and use of system charges	• Establish the principles of Use of System Charging Tariffs with the Regulator • There are no Use of System Charging Tariffs in place. **Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.** **Commence preparation of tariffs following completion of tariff principles.**	• Fully implement and annually review Use of System Charging Tariffs with the Regulator
6. Set interconnection charges based on CEER and ETSO Guidelines	• Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines • The Interconnection charging tariffs are awaiting the reorganisation of the industry and establishment of adequate generation capacity. • At present ZEKC assigns the interconnector transfer limits in cooperation with EPBiH, EPHZHB and EPRS. **Establishment of Interconnection Charging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.**	• Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines
7. Facilitate Market Operation, Inter	• Establish model Inter-country Trading Agreements • EPBiH AND EPHZHB: There are currently trading agreements with HEP Croatia and	• Manage congestion on a fully auditable basis

Country Trades and Manage Congestion	between the Bosnia and Herzegovina utilities EPBiH, EPRS and EPHZHB. Additionally EPRS has trading agreements with EPS Serbia and EPCG Montenegro. These can continue into initial market operation taking account of new rules. • There are no Commercial Codes or settlement rules for initial market operation. **Establishment of Inter-Country Trading Agreements is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.** • Establish Cross-Border Tariffs according to CEER and ETSO guidelines • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines for initial market operation as coordinated by ZEKC. **See comments in TSO Duty No. 6 above.** • Fully establish principles of Congestion Management process • The day ahead and on the day Congestion Management methods used in all three utilities are in line with the best utility practice and coordinated with ZEKC. **Carry out brief review of procedures to ensure compatibility with initial REM rules once the rules are established otherwise ready for initial REM.**	• Fully implement all Commercial Codes
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• Become proficient in calculating Ancillary Services Requirements • All three utilities obey UCTE rules for frequency control and have a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not calculated although the utility is fully capable to do so when needed. **See comments in TSO Duty No. 2 above.** • Establish Ancillary Services Pricing Principles • There are no Ancillary Services Pricing Principles, Contacts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. However, EPBiH has annual contracts with ERS to provide secondary control for one part of ERS consumer island operating in UCTE I synchronous zone. **See comments in TSO Duty No. 2 above.**	• Implement Ancillary Services Pricing Principles • Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring • The reactive power and voltage management processes need to be improved over the next two years for initial market operation. • As a minimum some basic Ancillary Services process needs to be put in place for initial market operation.
9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software yielding better results than commercial software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **See comments in TSO Duty No. 2 above.** • SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing

	• New SCADA/EMS under development by ZEKC to enable full control of all Bosnia and Herzegovina utilities. Initially all UCTE functionality and later market functionality will be incorporated. **The commissioning of the new SCADA/EMS should be expedited for initial market operation but the utility can manage with a few enhancements to its existing equipment.** • System Operation to merit order and establishing interconnector transfers • Economic scheduling and despatch calculations used in operating the system to a merit order in all three utilities. Interconnector transfers are determined by ZEKC and EKC. EKC carries out the overall interconnection transfer security coordination with the UCTE. **All three utilities ready for initial REM.** • Establish Operational Procedures **See comments in TSO Duty No. 2 above.** • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) **See comments in TSO Duty No. 2 above.** • Improve Congestion Management methods **See comments in TSO Duty No. 7 above.** • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code **See comments in TSO Duty No. 3 above.** • Management of Balancing and Settlement Information • Management of Balancing and Settlement Information can be handled by simple spreadsheets for initial market operation and specific software can be added to the new SCADA/EMS. **Establish simple spreadsheet for Balancing and Settlement for initial REM.**	Code • Focus on efficient congestion management • Full market based operation • Forecast sufficiently accurate for initial market operation some effort needs to be put in for Mvar forecasts for future full market operation. • A modern SCADA and EMS is essential and should be pursued on an urgent basis for initial market operation. • Scheduling and Dispatch Code is essential for initial market operation as part of the Grid Code.
10. Administer the settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **See comments in TSO Duty No. 9 above.**	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes • The accounting, settlement and dispute resolution processes need to be in place for initial market operation.
11. Facilitate information exchange between	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities • Implement information Exchange Protocol with UCTE	• Grid Code, Data Registration Code implemented in full • Market Information System implemented in full

dispatch centers and communicate with the market participants	• Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • At least a basic data registration and data exchange process needs to be in place to enable exchange of data between industry entities, with interconnected utilities, EKC and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** Sufficient metering and data collection facilities to enable market operation and billing • The current metering facilities are sufficiently accurate and adequate for initial REM in all three utilities. Some assumptions may be needed for settlement at initial REM. **All three utilities ready for initial REM perhaps with some minor work.**	• Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the system for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be a shortage of qualified staff, staff skills and training in all three utilities. These are essential for successful reform of utility and market operation. **See comments in TSO Duty No 2 above. Training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

13.3 CROATIA (HEP)

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities • Transmission system boundaries with generation and distribution are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. **Full establishment of the defined boundaries in legal terms required for initial REM.**	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy • The principles and priorities for asset replacement and investment strategy are well established. **Full Asset Register and Asset Replacement policy required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software yielding better results than commercial software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **Present load forecasting method adequate for initial REM. Mvar forecast data collection should be immediately undertaken to enable development for full REM.** • Establish a fully documented System Planning process • Planning Standards appear to be well established. Planning studies are carried out by the utility based on clear economic and financial criteria. **System Planning Process well established and ready for initial REM. Start training staff in system stability studies for full REM.** • Fully implement a sound System Operational Planning process • There is a well established operational planning and outage coordination process in place. **Operational Planning Process well established and ready for initial REM.** • Establish fully documented Security and Quality of Supply Standards • The (n-1) criterion is well understood and reasonably recorded in the Croatian Master Plan. **Review Security and Quality of Supply criteria for incorporation into the Grid Code for initial REM.** Implement full Power System Analysis Capability • The utility has some home grown software and the PSS/E package. It is reasonably capable of using these packages effectively on a daily basis in the planning and	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • The utility appears to have adequate maintenance practices and procedures in place. • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent contractors. **Review the load forecasting**

<table>
<tr><td></td><td>operational planning processes.
<u>The utility ready for initial REM. Start training staff in system stability studies for full REM.</u>
• <u>Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy)</u>
<u>The utility ready for initial REM.</u>
• <u>Establish all planning and operational procedures</u>
<u>The utility needs to review and re-establish planning and operational procedures and compliance with these procedures for initial REM.</u>
<u>Fully implement UCTE Rules</u>
• The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines.
• <u>Fully implement CEER and ETSO Guidelines</u>
• The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines.
• <u>Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start)</u>
• The utility obeys UCTE rules for frequency control and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so when needed.
<u>The reactive power and voltage management processes need to be improved for initial market operation.</u></td><td><u>process for Mvar forecast and accuracy in 2007 or 2008.</u>

<u>The Security and Quality of Supply Standards should be made uniform across the region and UCTE within the next two years to achieve a single application procedure.</u>

• The PSS/E software package is well recognised and staff appears to be adequately trained in its use with regular refresher training required for initial market operation.
• The reactive power and voltage management processes need to be improved over the next two years for initial market operation.</td></tr>
<tr><td>3. Enable Regulated Third Party Access</td><td>• <u>Establish basic Grid Code (Connection Conditions)</u>
• There is a draft HEP Grid Code which has not as yet been finalised.
<u>The bulk of the Grid Code is required for the initial REM to introduce necessary planning, operational planning and operational disciplines in preparation for full REM. The existing draft of Grid Code needs further work for completion. The utility could use the draft Grid Code for BiH as a template for compatible Grid Codes with other jurisdictions.</u>
• Although there is a draft HEP Grid Code, as yet there are no technical compliance processes in place.
<u>Preparation of the principles for the Grid Code Compliance Process should be progressed together with the development of the Grid Code.</u>
• <u>Establish model Connection Agreements</u>
• There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation.
<u>Establish template for model Connection Agreements suitable for different types of customers for initial REM. Estimated completion end 2006.</u>
• <u>Establish the principles of Use of System Charging Tariffs</u></td><td>• <u>Implementation of the full Grid Code</u>
• <u>Full implementation of Grid Code Compliance Processes and Monitoring</u>
• <u>Connection Agreements with all transmission customers</u></td></tr>
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	• There are no Use of System Charging Tariffs in place. **<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u>**	
4. Establish Grid Codes and compliance verification processes	<u>Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code)</u> **<u>See comments in TSO Duty No. 3 above.</u>** • <u>Establish Compliance Verification and Testing (for new connections only)</u> • Although there is a draft HEP Grid Code, as yet there are no technical compliance processes in place. **<u>Establish basic compliance verification and testing process for applicable to new connections for the initial REM.</u>**	• <u>Implement Full Grid Code</u> • <u>Implement Compliance Verification and Testing for all connections</u>
5. Set non-discriminatory connection and use of system charges	• <u>Establish the principles of Use of System Charging Tariffs with the Regulator</u> • There are no Use of System Charging Tariffs in place. **<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u>** **<u>Commence preparation of tariffs following completion of tariff principles.</u>**	• <u>Fully implement and annually review Use of System Charging Tariffs with the Regulator</u>
6. Set interconnection charges based on CEER and ETSO Guidelines	• <u>Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines</u> • The Interconnection charging tariffs are awaiting the reorganisation of the industry. • At present CRO ISMO (soon to become TSO Croatia) assigns the interconnector transfer limits in cooperation with EKC (Serbia & Montenegro), ZEKC (Bosnia & Herzegovina), TSO Slovenia and TSO Hungary • Establishment of Interconnection C**<u>harging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.</u>**	• <u>Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines</u>
7. Facilitate Market Operation, Inter Country Trades and Manage Congestion	• <u>Establish model Inter-country Trading Agreements</u> • There are currently trading agreements with power systems of MAVIR/MVM (Hungary), ELES (Slovenia), ERS (BiH), EPHZHB (BiH), EPBiH (BiH) and EPS (Serbia). These can continue into initial market operation taking account of new rules. • <u>Establish Cross-Border Tariffs according to CEER and ETSO guidelines</u> • There are no Commercial Codes or settlement rules for initial market operation. • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines. **<u>See comments in TSO Duty No. 6 above.</u>** • <u>Fully establish principles of Congestion Management process</u> • The day ahead and on the day Congestion Management methods are used in HEP. **<u>Carry out brief review of procedures to ensure compatibility with initial REM rules once the rules are established otherwise ready for initial REM.</u>**	• <u>Manage congestion on a fully auditable basis</u> • <u>Fully implement all Commercial Codes</u>
8. Contract for Ancillary	• <u>Become proficient in calculating Ancillary Services Requirements</u> • The utility obeys UCTE rules for frequency control and has a well established voltage	• <u>Implement Ancillary Services Pricing Principles</u>

Services (reactive power, reserve and Black Start)	control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so whenever needed. **See comments in TSO Duty No. 2 above.** • Establish Ancillary Services Pricing Principles • There are no Ancillary Services Pricing Principles, Contacts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. **See comments in TSO Duty No. 2 above.**	• Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring
9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software yielding better results than commercial software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **See comments in TSO Duty No. 2 above.** • SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • Existing SCADA/EMS is well equipped and adequate for initial market operation. The utility is developing its EMS to include as many EMS functions as possible to be real – time and on-line **The development of the SCADA/EMS should be expedited for initial market operation.** • System Operation to merit order and establishing interconnector transfers • The utility operates a merit order system which fully takes into account contractual obligations, hydrological data and unit prices of different types of generation. HEP operators decide levels of interconnector transfers subject to approval of CROISMO the system operator. **Utility ready for initial REM.** • Establish Operational Procedures **See comments in TSO Duty No. 2 above.** • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) **See comments in TSO Duty No. 2 above.** • Improve Congestion Management methods **See comments in TSO Duty No. 7 above.** • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code **See comments in TSO Duty No. 3 above.** • Management of Balancing and Settlement Information • Management of Balancing and Settlement Information can be handled by simple spreadsheets for initial market operation and specific software can be added to the	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code • Focus on efficient congestion management • Full market based operation

	existing SCADA/EMS. **Establish simple spreadsheet for Balancing and Settlement for initial REM.**	
10. Administer the settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **See comments in TSO Duty No. 9 above.**	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities • Implement information Exchange Protocol with UCTE • Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • At least a basic data registration and data exchange process needs to be in place to enable exchange of data between industry entities, with interconnected utilities and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** Sufficient metering and data collection facilities to enable market operation and billing • Utility has a modern metering and automatic data collection system already in place. **Utility fully ready for initial and full REM.**	• Grid Code, Data Registration Code implemented in full • Market Information System implemented in full • Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the system for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be sufficient qualified staff, staff skills and training. These are essential for successful reform of utility and market operation. Further skills will need to be added in the lead to initial market operation and to adequately respond to further market developments. **See comments in TSO Duty No. 2 above. Training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

13.4 MACEDONIA (ESM)

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities • Definition of transmission system boundaries with generation and distribution are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. **Full establishment of the defined boundaries in legal terms required for initial REM.**	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy • The principles and priorities for asset replacement and investment strategy are well established. **Full Asset Register required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software. Additionally SEETEC software is also being trialled to check forecast sensitivities. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **Present load forecasting method adequate for initial REM. Mvar forecast data collection should be immediately undertaken to enable development for full REM.** • Establish a fully documented System Planning process • Planning Standards appear to be quite sophisticated and well established. Planning studies are carried out by the utility based on clear economic and financial criteria. There is a comprehensive Least Cost Expansion Plan prepared by Harza and an Energy Sector Development Strategy. **System Planning Process well established and ready for initial REM. Start training staff in system stability studies for full REM.** • Fully implement a sound System Operational Planning process • There is a well established operational planning and outage coordination process in place. **Operational Planning Process well established and ready for initial REM.** • Establish fully documented Security and Quality of Supply Standards • The (n-1) criterion is well understood and reasonably recorded. Some (n-2) studies are carried out as part of the security criteria. Quality of Supply Standards are included in the existing Electricity Law which is now being redrafted to comply with EU Directives. **Complete brief review of Security and Quality of Supply criteria for**	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • The utility appears to have adequate maintenance practices and procedures in place. • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent contractors. **Review the load forecasting process for Mvar forecast and accuracy in 2007 or 2008.** **The Security and Quality of Supply Standards should be made uniform**

	incorporation into the Grid Code for initial REM. • Implement full Power System Analysis Capability • The utility has some home grown software and the PSS/E package. It is reasonably capable of using these packages effectively for steady state analysis on a daily basis in the planning and operational planning processes. **The utility ready for initial REM. Start training staff in system stability studies for full REM.** • Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy) **The utility ready for initial REM.** • Establish all planning and operational procedures **The utility needs to review and re-establish planning and operational procedures and compliance with these procedures for initial REM. Estimated completion mid to late 2005.** • Fully implement UCTE Rules • The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines. • Fully implement CEER and ETSO Guidelines • The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines. • Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start) • The utility obeys UCTE rules for frequency control in accordance with participation points calculated by EKC and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so when needed in collaboration with EKC. **The reactive power and voltage management processes need to be improved for initial market operation.**	**across the region and UCTE within the next two years to achieve a single application procedure.** • The PSS/E software package is well recognised and staff appears to be adequately trained in its use for steady state analysis with regular refresher training and essential dynamic analysis training required for initial market operation. • The reactive power and voltage management processes need to be improved over the next two years for initial market operation.
3. Enable Regulated Third Party Access	• Establish basic Grid Code (Connection Conditions) • There is no Grid Code. Its preparation awaiting the EDF donation. • Because there is no Grid Code there are, as yet, no technical compliance processes in place. **The bulk of the Grid Code is required for the initial REM to introduce necessary planning, operational planning and operational disciplines in preparation for full REM. The Grid Code needs to be completed by mid 2005. The utility could use the draft Grid Code for BiH as a template for**	• Implementation of the full Grid Code • Full implementation of Grid Code Compliance Processes and Monitoring • Connection Agreements with all transmission customers

	compatible Grid Codes with other jurisdictions. • Establish model Connection Agreements • There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation. **Establish template for model Connection Agreements suitable for different types of customers for initial REM.** • Establish the principles of Use of System Charging Tariffs • There are no Use of System Charging Tariffs in place. **Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.**	
4. Establish Grid Codes and compliance verification processes	• Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code) **See comments in TSO Duty No. 3 above.** • Establish Compliance Verification and Testing (for new connections only) • Because there is no Grid Code there are, as yet, no technical compliance processes in place. **Establish basic compliance verification and testing process for applicable to new connections for the initial REM.**	• Implement Full Grid Code • Implement Compliance Verification and Testing for all connections
5. Set non-discriminatory connection and use of system charges	• Establish the principles of Use of System Charging Tariffs with the Regulator • There are no Use of System Charging Tariffs in place. **Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.** **Commence preparation of tariffs following completion of tariff principles.**	• Fully implement and annually review Use of System Charging Tariffs with the Regulator
6. Set interconnection charges based on CEER and ETSO Guidelines	• Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines • The Interconnection charging tariffs are awaiting the reorganisation of the industry. • At present EKC assigns the interconnector transfer limits in cooperation with EPS (Serbia), KEK (UNMIK) and Greece. ESM and Bulgaria jointly assign transfers at 110kV non-synchronous interconnections. **Establishment of Interconnection Charging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.**	• Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines
7. Facilitate Market Operation, Inter Country Trades and Manage Congestion	• Establish model Inter-country Trading Agreements • There are currently trading agreements with power systems of EPS (Serbia), KEK (UNMIK) and Greece. ESM and Bulgaria jointly assign transfers at 110kV non-synchronous interconnections. These can continue into initial market	• Manage congestion on a fully auditable basis • Fully implement all Commercial Codes

	operation taking account of new rules. • Establish Cross-Border Tariffs according to CEER and ETSO guidelines • There are no Commercial Codes or settlement rules for initial market operation. • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines. **See comments in TSO Duty No. 6 above.** • Fully establish principles of Congestion Management process • The day ahead and on the day Congestion Management methods are used in ESM based upon load flow calculations carried out at the National Dispatch Centre. **Carry out brief review of procedures to ensure compatibility with initial REM rules once the rules are established otherwise ready for initial REM.**	
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• Become proficient in calculating Ancillary Services Requirements • The utility obeys UCTE rules for frequency control in accordance with participation points calculated by EKC and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable of doing so whenever needed in collaboration with EKC. **See comments in TSO Duty No. 2 above.** • Establish Ancillary Services Pricing Principles • There are no Ancillary Services Pricing Principles, Contracts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. **See comments in TSO Duty No. 2 above.**	• Implement Ancillary Services Pricing Principles • Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring
9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software. Additionally SEETEC software is also being trialled to check forecast sensitivities. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **See comments in TSO Duty No. 2 above.** • SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • A modern SCADA/EMS has just been installed. With the addition of further RTU's which are needed his should be adequate for initial market operation. The system is capable of being extended to include other up to date technical and market functionality. **The development of the SCADA/EMS should be expedited for initial market**	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code • Focus on efficient congestion management • Full market based operation

	<u>operation.</u> • <u>System Operation to merit order and establishing interconnector transfers</u> • The utility operates a merit order system which fully takes into account contractual obligations, hydrological data and unit prices of different types of generation. ECM operators decide levels of interconnector transfers and EKC carries out the overall interconnection transfer security coordination with the UCTE. **<u>Utility ready for initial REM.</u>** • <u>Establish Operational Procedures</u> **<u>See comments in TSO Duty No. 2 above.</u>** • <u>Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start)</u> **<u>See comments in TSO Duty No. 2 above.</u>** • <u>Improve Congestion Management methods</u> **<u>See comments in TSO Duty No. 7 above.</u>** • <u>Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code</u> **<u>See comments in TSO Duty No. 3 above.</u>** • <u>Management of Balancing and Settlement Information</u> Management of Balancing and Settlement Information can be handled by simple spreadsheets for initial market operation and specific software can be added to the existing SCADA/EMS. **<u>Establish simple spreadsheet for Balancing and Settlement for initial REM.</u>**	
10. Administer the settlements process	• <u>Basic Use of System Revenue Accounting</u> • <u>Basic Administration of Energy Accounts Settlement</u> • <u>Dispute Resolution Processes</u> • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **<u>See comments in TSO Duty No. 9 above.</u>**	• <u>Full Use of System Revenue Accounting</u> • <u>Full Administration of Energy Accounts Settlement</u> • <u>Dispute Resolution Processes</u>
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• <u>Grid Code, Data Registration Code implemented for new connections only</u> • <u>Agree Regulatory Reporting requirements</u> • <u>Establish basic Data Registration and Exchange Facilities</u> • <u>Implement information Exchange Protocol with UCTE</u> • <u>Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities</u> • <u>CEER and ETSO Guidelines</u> • At least a basic data registration and data exchange process needs to be in	• <u>Grid Code, Data Registration Code implemented in full</u> • <u>Market Information System implemented in full</u> • <u>Fully implemented Regulatory Reporting Requirements</u> • <u>Publish annually a statement on the Connection Opportunities to the system</u>

	place to enable exchange of data between industry entities, with interconnected utilities and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** • Sufficient metering and data collection facilities to enable market operation and billing • Existing metering sufficiently accurate for initial REM although some assumptions may have to be made for the settlement process. **Utility essentially ready for initial REM perhaps with some minor work.**	for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be sufficient qualified staff, staff skills and training. These are essential for successful reform of utility and market operation. Further skills will need to be added in the lead to initial market operation and to adequately respond to further market developments. **See comments in TSO Duty No. 2 above. Training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

13.5 MONTENEGRO (EPCG)

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities • Definition of transmission system boundaries with generation and distribution are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. **Full establishment of the defined boundaries in legal terms required for initial REM.**	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy • The principles and priorities for asset replacement and investment strategy are well established. **Full Asset Register required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software up to a year ahead. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **Present load forecasting method adequate for initial REM. Mvar forecast data collection should be immediately undertaken to enable development for full REM.** • Establish a fully documented System Planning process • Planning Standards appear to be well established. Planning studies are carried out as required the last detailed study being in 1997. There is a well established operational planning and outage coordination process in place. **System Planning Process well established and ready for initial REM. Start training staff in system stability studies for full REM.** • Fully implement a sound System Operational Planning process • There is a well established operational planning and outage coordination process in place. **Operational Planning Process well established and ready for initial REM.** • Establish fully documented Security and Quality of Supply Standards The (n-1) criterion is well understood and reasonably recorded. Quality of Supply Standards are based on provision of a second supply route and need to be explicitly recorded. **Complete recording of Security and Quality of Supply criteria for incorporation into the Grid Code for initial REM.** • Implement full Power System Analysis Capability • The utility has some home grown software and the PSS/E package. It is	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • The utility appears to have adequate maintenance practices and procedures in place. • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent contractors. **Review the load forecasting process for Mvar forecast and accuracy in 2007 or 2008.**

	reasonably capable of using these packages effectively for steady state analysis on a daily basis in the planning and operational planning processes. **The utility ready for initial REM. Start training staff in system stability studies for full REM.** • Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy) **The utility ready for initial REM.** • Establish all planning and operational procedures **The utility needs to review and re-establish planning and operational procedures and compliance with these procedures for initial REM.** • Fully implement UCTE Rules • The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines. • Fully implement CEER and ETSO Guidelines • The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines. • Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start) • The utility obeys UCTE rules for frequency control in accordance with participation points calculated by EKC and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable of doing so when needed in collaboration with EKC. **The reactive power and voltage management processes need to be improved for initial market operation.** • The utility does not have any automatic low frequency load shedding facilities in place for managing system emergencies. Load shedding is carried out manually by operator instruction. **The utility needs to establish automatic load shedding facilities to harmonise itself with all other utility practices. At least 55% of the total peak demand needs to be assigned to low frequency relay based automatic load shedding.**	**The Security and Quality of Supply Standards should be made uniform across the region and UCTE within the next two years to achieve a single application procedure.** • The PSS/E software package is well recognised and staff appears to be adequately trained in its use for steady state analysis with regular refresher training and essential dynamic analysis training required for initial market operation. • The reactive power and voltage management processes need to be improved over the next two years for initial market operation. • Automatic low frequency load shedding in line with the rest of the utilities in the area need to be installed within the next two years.
3. Enable Regulated Third Party Access	• Establish basic Grid Code (Connection Conditions) • There is no Grid Code. Its preparation awaiting the EDF donation. There is a high level Working Group formed to oversee the preparation of the Grid Code. • There is no Grid Code. Therefore as yet there are no technical compliance processes in place. **The bulk of the Grid Code is required for the initial REM to introduce**	• Implementation of the full Grid Code • Full implementation of Grid Code Compliance Processes and Monitoring • Connection Agreements with all transmission customers

	<u>necessary planning, operational planning and operational disciplines in preparation for full REM. The Grid Code needs to be completed by mid 2005. The utility could use the draft Grid Code for BiH as a template for compatible Grid Codes with other jurisdictions.</u> • <u>Establish model Connection Agreements</u> • There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation. **<u>Establish template for model Connection Agreements suitable for different types of customers for initial REM.</u>** • <u>Establish the principles of Use of System Charging Tariffs</u> • There are no Use of System Charging Tariffs in place. **<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u>**	
4. Establish Grid Codes and compliance verification processes	• <u>Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code)</u> **<u>See comments in TSO Duty No. 3 above.</u>** • <u>Establish Compliance Verification and Testing (for new connections only)</u> • There is no Grid Code. Its preparation awaiting the EDF donation. There is a high level Working Group formed to oversee the preparation of the Grid Code. Therefore as yet there are no technical compliance processes in place. **<u>Establish basic compliance verification and testing process for applicable to new connections for the initial REM.</u>**	• <u>Implement Full Grid Code</u> • <u>Implement Compliance Verification and Testing for all connections</u>
5. Set non-discriminatory connection and use of system charges	• <u>Establish the principles of Use of System Charging Tariffs with the Regulator</u> There are no Use of System Charging Tariffs in place. **<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u>** **<u>Commence preparation of tariffs following completion of tariff principles.</u>**	• <u>Fully implement and annually review Use of System Charging Tariffs with the Regulator</u>
6. Set interconnection charges based on CEER and ETSO Guidelines	• <u>Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines</u> • The Interconnection charging tariffs are awaiting the reorganisation of the industry. • At present EKC assigns the interconnector transfer limits in cooperation with EPS (Serbia), KESH (Albania) and EPRS (BiH). **<u>Establishment of Interconnection Charging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.</u>**	• <u>Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines</u>
7. Facilitate Market	• <u>Establish model Inter-country Trading Agreements</u>	• <u>Manage congestion on a fully</u>

Operation, Inter Country Trades and Manage Congestion	• There are currently trading agreements with power systems of EPS (Serbia), KESH (Albania) and EPRS (BiH). These can continue into initial market operation taking account of new rules. • Establish Cross-Border Tariffs according to CEER and ETSO guidelines • There are no Commercial Codes or settlement rules for initial market operation. • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines. **See comments in TSO Duty No. 6 above.** • Fully establish principles of Congestion Management process • There are no bottlenecks or constraints on the system for the foreseeable future. At this moment EPCG does not use any kind of criteria used for transmission reinforcements for congestion elimination. **Carry out brief review of procedures to ensure compatibility with initial REM rules once the rules are established otherwise ready for initial REM.**	auditable basis • Fully implement all Commercial Codes
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• Become proficient in calculating Ancillary Services Requirements • The utility obeys UCTE rules for frequency control in accordance with participation points calculated by EKC and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so whenever needed in collaboration with EKC. **See comments in TSO Duty No. 2 above.** • Establish Ancillary Services Pricing Principles • There are no Ancillary Services Pricing Principles, Contacts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. **See comments in TSO Duty No. 2 above.**	• Implement Ancillary Services Pricing Principles • Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring
9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **See comments in TSO Duty No. 2 above.** • SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • The existing home grown SCADA/EMS is currently being improved. All substations will be equipped with RTU's which should make it adequate for initial market operation. The system is capable of being extended to include other up to date technical and market functionality. **The development of the SCADA/EMS should be expedited for initial market**	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code • Focus on efficient congestion management • Full market based operation

	operation. • System Operation to merit order and establishing interconnector transfers • The utility operates a merit order system which fully takes into account contractual obligations, hydrological data and unit prices of different types of generation. EPCG operators decide levels of interconnector transfers and EKC carries out the overall interconnection transfer security coordination with the UCTE. **Utility ready for initial REM.** • Establish Operational Procedures **See comments in TSO Duty No. 2 above.** • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) **See comments in TSO Duty No. 2 above.** • Improve Congestion Management methods **See comments in TSO Duty No. 7 above.** • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code **See comments in TSO Duty No. 3 above.** • Management of Balancing and Settlement Information • Management of Balancing and Settlement Information can be handled by simple spreadsheets for initial market operation and specific software can be added to the existing SCADA/EMS. **Establish simple spreadsheet for Balancing and Settlement for initial REM.**	
10. Administer the settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **See comments in TSO Duty No. 9 above.**	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities • Implement information Exchange Protocol with UCTE • Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • At least a basic data registration and data exchange process needs to be in place	• Grid Code, Data Registration Code implemented in full • Market Information System implemented in full • Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the

	to enable exchange of data between industry entities, with interconnected utilities and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** • Sufficient metering and data collection facilities to enable market operation and billing • Existing metering is accurate and metering data collection facilities are automatic fully ready for both initial and full REM. **Utility fully ready for both initial and final REM.**	system for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be sufficient qualified staff, staff skills and training. These are essential for successful reform of utility and market operation. Further skills will need to be added in the lead to initial market operation and to adequately respond to further market developments. **See comments in TSO Duty No. 2 above. Training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

13.6 SERBIA (EPS)

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities • Definition of transmission system boundaries with generation and distribution are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. **Full establishment of the defined boundaries in legal terms required for initial REM.**	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy • The principles and priorities for asset replacement and investment strategy are well established. **Full Asset Register required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **Present load forecasting method adequate for initial REM. Mvar forecast data collection should be immediately undertaken to enable development for full REM.** • Establish a fully documented System Planning process • Planning Standards appear to be quite sophisticated and well established. Planning studies are carried out for the utility by the Nikola Tesla Institute Belgrade as well as the utility Research Department based on clear economic and financial criteria. **System Planning Process well established and ready for initial REM. Start training staff in system stability studies for full REM.** • Fully implement a sound System Operational Planning process • There is a well established operational planning and outage coordination process in place. **Operational Planning Process well established and ready for initial REM.** • Establish fully documented Security and Quality of Supply Standards • The (n-1) criterion is well understood and reasonably recorded. Some (n-2) studies are carried out as part of the security criteria. Quality of Supply Standards are included in operational rulebooks of the utility. **After a brief review Security and Quality of Supply criteria are ready for incorporation into the Grid Code for initial REM.** • Implement full Power System Analysis Capability The utility has some home grown software and the PSS/E package. It is	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • The utility appears to have adequate maintenance practices and procedures in place. • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent contractors. **Review the load forecasting process for Mvar forecast and accuracy in 2007 or 2008.**

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<td>reasonably capable of using these packages effectively for steady state analysis on a daily basis in the planning and operational planning processes.
<u>The utility ready for initial REM. Start training staff in system stability studies for full REM.</u>
• <u>Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy)</u>
<u>The utility ready for initial REM.</u>
• <u>Establish all planning and operational procedures</u>
<u>The utility needs to review and re-establish planning and operational procedures and compliance with these procedures for initial REM. Estimated completion early 2005.</u>
• <u>Fully implement UCTE Rules</u>
• The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines.
• <u>Fully implement CEER and ETSO Guidelines</u>
• The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines.
• <u>Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start)</u>
• The utility obeys UCTE rules for frequency control in accordance with participation points calculated by EKC and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so when needed in collaboration with EKC.
<u>The reactive power and voltage management processes need to be improved for initial market operation.</u></td>
<td><u>The Security and Quality of Supply Standards should be made uniform across the region and UCTE within the next two years to achieve a single application procedure.</u>
• The PSS/E software package is well recognised and staff appears to be adequately trained in its use for steady state analysis with regular refresher training and essential dynamic analysis training required for initial market operation.
• The reactive power and voltage management processes need to be improved over the next two years for initial market operation.</td>
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<td>3. Enable Regulated Third Party Access</td>
<td>• <u>Establish basic Grid Code (Connection Conditions)</u>
• There is no Grid Code. Its preparation awaiting the EDF donation. However, preparation of Grid Code will be made easy through the presence of the existing rulebooks.
• Because there is no Grid Code there are, as yet, no technical compliance processes in place.
<u>The bulk of the Grid Code is required for the initial REM to introduce necessary planning, operational planning and operational disciplines in preparation for full REM. The Grid Code needs to be completed by mid 2005. The utility could use the draft Grid Code for BiH as a template for compatible Grid Codes with other jurisdictions.</u>
• <u>Establish model Connection Agreements</u></td>
<td>• <u>Implementation of the full Grid Code</u>
• <u>Full implementation of Grid Code Compliance Processes and Monitoring</u>
• <u>Connection Agreements with all transmission customers</u></td>
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<tr><td></td><td>• There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation.
<u>Establish template for model Connection Agreements suitable for different types of customers for initial REM.</u>
• <u>Establish the principles of Use of System Charging Tariffs</u>
• There are no Use of System Charging Tariffs in place.
<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u></td><td></td></tr>
<tr><td>4. Establish Grid Codes and compliance verification processes</td><td>• <u>Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code)</u>
<u>See comments in TSO Duty No. 3 above.</u>
• <u>Establish Compliance Verification and Testing (for new connections only)</u>
• Because there is no Grid Code there are, as yet, no technical compliance processes in place.
<u>Establish basic compliance verification and testing process for applicable to new connections for the initial REM.</u></td><td>• <u>Implement Full Grid Code</u>
• <u>Implement Compliance Verification and Testing for all connections</u></td></tr>
<tr><td>5. Set non-discriminatory connection and use of system charges</td><td>• <u>Establish the principles of Use of System Charging Tariffs with the Regulator</u>
• There are no Use of System Charging Tariffs in place.
<u>Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.</u>

<u>Commence preparation of tariffs following completion of tariff principles.</u></td><td>• <u>Fully implement and annually review Use of System Charging Tariffs with the Regulator</u></td></tr>
<tr><td>6. Set interconnection charges based on CEER and ETSO Guidelines</td><td>• <u>Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines</u>
• The Interconnection charging tariffs are awaiting the reorganisation of the industry.
• At present EKC assigns the interconnector transfer limits in cooperation with EPS (Serbia), KEK (UNMIK), MVM/MAVIR (Hungary), Transelectrica (Romania), NEK (Bulgaria) ESM (Macedonia), EPCG (Montenegro), HEP (Croatia) and EPRS (BiH).
<u>Establishment of Interconnection Charging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.</u></td><td>• <u>Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines</u></td></tr>
<tr><td>7. Facilitate Market Operation, Inter Country Trades and Manage Congestion</td><td>• <u>Establish model Inter-country Trading Agreements</u>
• There are currently trading agreements with power systems of EPS (Serbia), KEK (UNMIK), MVM/MAVIR (Hungary), Transelectrica (Romania), NEK (Bulgaria) ESM (Macedonia), EPCG (Montenegro), HEP (Croatia) and EPRS (BiH). These can continue into initial market operation taking account of new rules.</td><td>• <u>Manage congestion on a fully auditable basis</u>
• <u>Fully implement all Commercial Codes</u></td></tr>
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	• <u>Establish Cross-Border Tariffs according to CEER and ETSO guidelines</u> There are no Commercial Codes or settlement rules for initial market operation. • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines. **<u>See comments in TSO Duty No. 6 above.</u>** • <u>Fully establish principles of Congestion Management process</u> • The day ahead and on the day Congestion Management methods are used in EPS based upon load flow calculations carried out at the National Dispatch Centre. The outages and congestion management is jointly carried out in collaboration with EKC. **<u>Carry out brief review of procedures to ensure compatibility with initial REM rules once the rules are established otherwise ready for initial REM.</u>**	
8. Contract for Ancillary Services (reactive power, reserve and Black Start)	• <u>Become proficient in calculating Ancillary Services Requirements</u> • The utility obeys UCTE rules for frequency control in accordance with participation points calculated by EKC and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so whenever needed in collaboration with EKC. **<u>See comments in TSO Duty No. 2 above.</u>** • <u>Establish Ancillary Services Pricing Principles</u> • There are no Ancillary Services Pricing Principles, Contacts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. **<u>See comments in TSO Duty No. 2 above.</u>**	• <u>Implement Ancillary Services Pricing Principles</u> • <u>Establish Ancillary Services Contracts</u> • <u>Establish and operate Ancillary Services Contract Delivery Monitoring</u>
9. Schedule and dispatch generation	• <u>Establish an accurate Load Forecasting method and process</u> • Load Forecasting is carried out based upon home grown software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **<u>See comments in TSO Duty No. 2 above.</u>** • <u>SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation</u> • The existing SCADA/EMS has just been installed should be adequate for initial market operation. A new SCADA/EMS system is currently being planned for completion in 2007 with the latest technical functionality and facilities for incorporating market functions. **<u>The development of the SCADA/EMS should be expedited for initial market operation.</u>** • <u>System Operation to merit order and establishing interconnector transfers</u>	• <u>Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation</u> • <u>System Incident Investigation</u> • <u>Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code</u> • <u>Focus on efficient congestion management</u> • <u>Full market based operation</u>

	• The utility operates a merit order system which fully takes into account contractual obligations, hydrological data and unit prices of different types of generation. EPS operators decide levels of interconnector transfers and EKC carries out the overall interconnection transfer security coordination with the UCTE. **Utility ready for initial REM.** • Establish Operational Procedures **See comments in TSO Duty No. 2 above.** • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) **See comments in TSO Duty No. 2 above.** • Improve Congestion Management methods **See comments in TSO Duty No. 7 above.** • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code **See comments in TSO Duty No. 3 above.** • Management of Balancing and Settlement Information • Management of Balancing and Settlement Information can be handled by simple spreadsheets for initial market operation and specific software can be added to the existing SCADA/EMS. **Establish simple spreadsheet for Balancing and Settlement for initial REM.**	
10. Administer the settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **See comments in TSO Duty No. 9 above.**	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities • Implement information Exchange Protocol with UCTE • Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • At least a basic data registration and data exchange process needs to be in place to enable exchange of data between industry entities, with interconnected utilities	• Grid Code, Data Registration Code implemented in full • Market Information System implemented in full • Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the system for generation and demand over the next 5-10 years

	and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** • Sufficient metering and data collection facilities to enable market operation and billing • Existing metering is accurate and metering data collection facilities are automatic fully ready for both initial and full REM. **Utility fully ready for both initial and final REM.**	
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be sufficient qualified staff, staff skills and training. These are essential for successful reform of utility and market operation. Further skills will need to be added in the lead to initial market operation and to adequately respond to further market developments. **See comments in TSO Duty No. 2 above. Training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

13.7 UNMIK

TSO DUTIES	ACTIVITIES/COMPETENCES FOR INITIAL REM	ADDITIONAL ACTIVITIES/COMPETENCES FOR FULL REM
1. Asset Ownership and Operation	• Establish clear definition of Asset Boundaries with Generation and Distribution entities • Definition of transmission system boundaries with generation and distribution are well defined. This will enable preparation of full asset register and valuation to form use of system charges needed for initial market operation. Generation boundaries will require definition. **Full establishment of the defined boundaries in legal terms required for initial REM.**	• Implement full Asset Register • Establish an Asset Replacement, Refurbishment and Investment Policy • The principles and priorities for asset replacement and investment strategy are well established via the ESTAP Master Plan. **Full Asset Register required for full REM.**
2. Develop and maintain an efficient, co-ordinated and economical transmission system within Security and Quality of Supply Standards	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software yielding better results than commercial software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **Present load forecasting method adequate for initial REM. Mvar forecast data collection should be immediately undertaken to enable development for full REM.** • Establish a fully documented System Planning process • Planning Standards appear to be well established. Planning studies are carried out by the utility based on clear economic and financial criteria. **System Planning Process well established and ready for initial REM. Start training staff in system stability studies for full REM.** • Fully implement a sound System Operational Planning process • There is a well established operational planning and outage coordination process in place. **Operational Planning Process well established and ready for initial REM.** • Establish fully documented Security and Quality of Supply Standards • The (n-1) criterion is well understood and reasonably recorded in the ESTAP Master Plan. The Security and Quality of Supply Standards are currently being recorded. **Complete recording of Security and Quality of Supply criteria for incorporation into the Grid Code for initial REM. Estimated completion mid to late 2005.** • Implement full Power System Analysis Capability • The utility has some home grown software and the PSS/E package. It is reasonably capable of using these packages effectively for steady state analysis on a daily basis in the planning and operational planning processes.	• Optimised and efficient system design and operation • Focused transmission investments based on elimination of congestion costs, bottlenecks and facilitating new generation and demand connections as well as interconnectors • Monitor system operational efficiency • Establish modern Maintenance Practices • The utility appears to have adequate maintenance practices and procedures in place. • Establish modern Construction Project Management • The utility appears competent to manage construction projects undertaken by competent contractors. **Review the load forecasting process for Mvar forecast and**

	The utility ready for initial REM. Start training staff in system stability studies for full REM. • Operate System fully to Security and Quality of Supply Standards (any non compliance can be derogated with a set time limit for remedy) **The utility ready for initial REM after completion of recording the criteria.** • Establish all planning and operational procedures **The utility needs to review and re-establish planning and operational procedures and compliance with these procedures for initial REM.** • Fully implement UCTE Rules • The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines. • Fully implement CEER and ETSO Guidelines • The utility is well aware of the UCTE rules as well as CEER and ETSO guidelines. • Establish processes for accurately calculating Ancillary Services Requirements (within UCTE rules for active power reserve for frequency and reactive reserve for voltage control plus black start) • The utility obeys UCTE rules for frequency control by procuring secondary frequency control from EPS Serbia and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so when needed in collaboration with EKC. **The reactive power and voltage management processes need to be improved for initial market operation.**	**accuracy in 2007 or 2008.** **The Security and Quality of Supply Standards should be made uniform across the region and UCTE within the next two years to achieve a single application procedure.** • The PSS/E software package is well recognised and staff appears to be adequately trained in its use for steady state analysis with regular refresher training and essential dynamic analysis training required for initial market operation. • The reactive power and voltage management processes need to be improved over the next two years for initial market operation.
3. Enable Regulated Third Part Access	• Establish basic Grid Code (Connection Conditions) • There is no Grid Code. Its preparation awaiting the EDF donation. **The bulk of the Grid Code is required for the initial REM to introduce necessary planning, operational planning and operational disciplines in preparation for full REM. The Grid Code needs to be completed by mid 2005. The utility could use the draft Grid Code for BiH as a template for compatible Grid Codes with other jurisdictions.** • Because there is no Grid Code there are, as yet, no technical compliance processes in place. **Preparation of the principles for the Grid Code Compliance Process should be progressed together with the development of the Grid Code.** • Establish model Connection Agreements • There are some connection agreements with large customers but these will have to be modified to reflect new market and industry reorganisation. **Establish template for model Connection Agreements suitable for different types of customers for initial REM. Estimated** • Establish the principles of Use of System Charging Tariffs	• Implementation of the full Grid Code • Full implementation of Grid Code Compliance Processes and Monitoring • Connection Agreements with all transmission customers

	• There are no Use of System Charging Tariffs in place. **Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.**	
4. Establish Grid Codes and compliance verification processes	• Establish bulk of the Grid Code (Security and Quality of Supply Standards, Connection Conditions, Planning Code, Operating Codes, Basic Data Registration Code) **See comments in TSO Duty No. 3 above.** • Establish Compliance Verification and Testing (for new connections only) • Because there is no Grid Code there are, as yet, no technical compliance processes in place. **Establish basic compliance verification and testing process for applicable to new connections for the initial REM.**	• Implement Full Grid Code • Implement Compliance Verification and Testing for all connections
5. Set non-discriminatory connection and use of system charges	• Establish the principles of Use of System Charging Tariffs with the Regulator • There are no Use of System Charging Tariffs in place. **Establish the principles of Use of System Charging Tariffs to facilitate industry reform for initial REM.** **Commence preparation of tariffs following completion of tariff principles.**	• Fully implement and annually review Use of System Charging Tariffs with the Regulator
6. Set interconnection charges based on CEER and ETSO Guidelines	• Establish Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines • The Interconnection charging tariffs are awaiting the reorganisation of the industry. • At present EKC assigns the interconnector transfer limits in cooperation with EPS (Serbia), ECM (Macedonia), KESH (Albania) and EPCG (Montenegro). **Establishment of Interconnection Charging Tariffs is absolutely necessary for the initial REM and need to be completed on a priority basis. Required by end 2005 in accordance with EC timetable.**	• Review Interconnection Charging Tariffs (Cross-Border Tariffs) based on CEER and ETSO Guidelines
7. Facilitate Market Operation, Inter Country Trades and Manage Congestion	• Establish model Inter-country Trading Agreements • There are currently trading agreements with power systems of EPS (Serbia), ECM (Macedonia), KESH (Albania) and EPCG (Montenegro). These can continue into initial market operation taking account of new rules. • Establish Cross-Border Tariffs according to CEER and ETSO guidelines • There are no Commercial Codes or settlement rules for initial market operation. • Cross Border Tariffs will need to be set in accordance with CEER and ETSO guidelines. **See comments in TSO Duty No. 6 above.** • Fully establish principles of Congestion Management process • The day ahead and on the day Congestion Management methods are used in KEK which includes load shedding due to 110kV system inadequacies. **Carry out brief review of procedures to ensure compatibility with initial REM rules once the rules are established otherwise ready for initial REM.**	• Manage congestion on a fully auditable basis • Fully implement all Commercial Codes
8. Contract for Ancillary	• Become proficient in calculating Ancillary Services Requirements • The utility obeys UCTE rules for frequency control by procuring secondary frequency	• Implement Ancillary Services Pricing Principles

Services (reactive power, reserve and Black Start)	control from EPS Serbia and has a well established voltage control culture. However, Ancillary Services requirements especially reactive power reserve for voltage control are at present not regularly calculated although the utility is fully capable to do so whenever needed in collaboration with EKC. **See comments in TSO Duty No. 2 above.** • Establish Ancillary Services Pricing Principles • There are no Ancillary Services Pricing Principles, Contacts and Contract Delivery Monitoring at present. As a minimum some basic Ancillary Services process needs to be put in place for initial market operation. **See comments in TSO Duty No. 2 above.**	• Establish Ancillary Services Contracts • Establish and operate Ancillary Services Contract Delivery Monitoring
9. Schedule and dispatch generation	• Establish an accurate Load Forecasting method and process • Load Forecasting is carried out based upon home grown software yielding better results than commercial software. Currently only MW is forecast but efforts need to be made to start the Mvar forecast for both long and short term use. The database for this purpose needs to be started as soon as possible. **See comments in TSO Duty No. 2 above.** • SCADA, EMS, data transfer and other operational facilities that include mechanisms enabling initial market operation • Existing SCADA/EMS is being refurbished with a mini SCADA and may just be adequate for initial market operation. It is unlikely that the mini SCADA will be able to cope with market functions. There is a new SCADA/EMS project being developed by the World Bank which will be capable to include all necessary technical and market functionality. **The development of the SCADA/EMS should be expedited for initial market operation.** • System Operation to merit order and establishing interconnector transfers • Plant is dispatched in merit order based upon cost information received from power stations. Interconnector transfers are also scheduled by the Pristina control center. EKC carries out the overall interconnection transfer security coordination with the UCTE. **Given its culture the utility ready for initial REM.** • Establish Operational Procedures **See comments in TSO Duty No. 2 above.** • Ancillary Services Requirements (within UCTE rules for frequency and reactive reserve for voltage control plus black start) **See comments in TSO Duty No. 2 above.** • Improve Congestion Management methods **See comments in TSO Duty No. 7 above.** • Establish and implement basic Grid Code and Scheduling and Dispatch and/or System Balancing Code **See comments in TSO Duty No. 3 above.** • Management of Balancing and Settlement Information. This can be handled by simple spreadsheets for initial market operation and specific software can be added to the	• Full SCADA/EMS and other operational facilities that include mechanisms enabling market operation • System Incident Investigation • Implementation of the full Grid Code and Scheduling and Dispatch and/or System Balancing Code • Focus on efficient congestion management • Full market based operation

	existing SCADA/EMS. **Establish simple spreadsheet for Balancing and Settlement for initial REM.**	
10. Administer the Settlements process	• Basic Use of System Revenue Accounting • Basic Administration of Energy Accounts Settlement • Dispute Resolution Processes • The Use of System Revenue Accounting should be in place together with a Settlement Process to enable determination of payments between generation, transmission and distribution entities for initial market operation. A basic dispute resolution process is also essential. **See comments in TSO Duty No. 9 above.**	• Full Use of System Revenue Accounting • Full Administration of Energy Accounts Settlement • Dispute Resolution Processes
11. Facilitate information exchange between dispatch centers and communicate with the market participants	• Grid Code, Data Registration Code implemented for new connections only • Agree Regulatory Reporting requirements • Establish basic Data Registration and Exchange Facilities • Implement information Exchange Protocol with UCTE • Implement basic information Exchange Protocols with Distco's and Neighbouring Utilities • CEER and ETSO Guidelines • At least a basic data registration and data exchange process needs to be in place to enable exchange of data between industry entities, with interconnected utilities and UCTE for initial market operation. • The rest of the requirements can be gradually developed as the market operation progresses. **All above processes need to be in place for initial REM.** • Sufficient metering and data collection facilities to enable market operation and billing • Existing metering sufficiently accurate for initial REM although some assumptions may have to be made for the settlement process. **Utility essentially ready for initial REM perhaps with some minor work.**	• Grid Code, Data Registration Code implemented in full • Market Information System implemented in full • Fully implemented Regulatory Reporting Requirements • Publish annually a statement on the Connection Opportunities to the system for generation and demand over the next 5-10 years
12. Staff Skills and Training	• Ensuring adequate staff skills and training in traditional utility management and technical competences • Training of staff in Market Operation (new skills) • Training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures • There appears to be sufficient qualified staff, staff skills and training. These are essential for successful reform of utility and market operation. Further skills will need to be added in the lead to initial market operation and to adequately respond to further market developments. **See comments in TSO Duty No. 2 above. Training needs to commence early to familiarise staff with all the new processes that need to be put in place as well as technical areas for the initial REM.**	• Continued development and training of staff in Market Operation (new skills) • Continued development and training of staff in traditional skills in areas of inadequacy • Hold desktop exercises to train and improve confidence of staff in new processes and procedures

14 STANDARDS AND PROCEDURES REQUIRED IN THE MARKET ENVIRONMENT FOR THE INTIAL AND FULL REMs

In addition to the standards and planning and operational and procedures listed in Section 6 above, which will need to be developed commensurate with the recommendations in Section 11 above, the following procedures will be required for each utility.

DOCUMENTS	ACTIVITIES/COMPETENCES	REQUIRED FOR INITIAL REM	ADDITIONALLY REQUIRED FOR FULL REM
Standards			
Contingencies	• Supply capacity following secured contingencies;	• This is a local issue but needs to be resolved so that customers understand the quality of supply they may expect.	• Security and Quality of Supply Standards should be uniform across the region for the full REM.
Planning Procedures			
Customer Service	• Connection application planning • Opportunities for connection	• Not specifically relevant to the REM but must be in place before company privatisation. • As above	• Not specifically relevant to the REM but must be in place before company privatisation. • As above
Operational Procedures			
Compliance	• Grid Code	• Must determine the process of complying with all aspects of the Grid Code that are in place at this stage	• Must have in place and conform to the process of complying with all aspects of the Grid Code
Operations	• Management of customer interfaces	• Not specifically a market requirement but will be required in an unbundled utility	• Not specifically a market requirement but will be required in an unbundled utility
Ancillary Services and Control	• Management of Area Control Error	• Current methods are satisfactory but a procedure needs to be developed	• Procedure required before the full REM
Contingencies	• Control incident centre and emergency evacuation	• Not specifically a requirement of the market but needs to be developed as the control centre increases in sophistication	• As opposite
Reporting	• Internal and regulator event reporting • Annual report to the regulator	• The process needs to be developed and agreed with the regulator • The process needs to be developed and agreed with the regulator	• No further action required • No further action required

15 CONCLUSIONS AND RECOMMENDATIONS

From the analysis presented in Section 13 above and given the specific characteristics of the utilities in the SEE Region the following conclusions can be drawn:

1. In terms of their readiness for the initial and subsequently for the final REM there are three distinct classes of utilities, namely those in;
   i. highest state of readiness which include Serbia, Montenegro, Macedonia and Croatia;
   ii. reasonable state of readiness which include BiH utilities of EPBiH, EPHZHB and EPRS as well as UNMIK; and
   iii. need of additional assistance over and above others which include Albania.
2. The utilities which are in a state of high and reasonable readiness have a lot of the basic requirements for the initial and final REM already in place or are in a state where the work to complete these in the timescales required by the EU can be readily expedited by making necessary resources available.
3. In addition the utilities in a high state of readiness have the necessary culture, discipline, rules, procedures and practices largely in place. These form the basis of preparing the Grid Codes and the Commercial Codes that need to be put in place in a harmonised manner across the Region to enable the SEE REM.
4. In terms of transmission activities the BiH utilities need to be combined under a single entity. Failure to do so would result in very many transmission lines at 110kV level to be recognised as interconnectors and thus create a high level of bureaucracy in managing transfers across the region. Combining the transmission capabilities of the three BiH utilities with the technical capabilities of ZEKC would be an ideal solution which would put the entire BiH area under a high state of readiness for the initial and final REM.
5. There is a specific need for a single template Grid Code for the utilities in the Region. The draft Grid Code prepared for BiH provides an excellent template for a National Grid Codes. Use of this as a template will also enable completion of this most essential task in a relatively short time.
6. There is an overarching need for the Security and Quality of Supply criteria to be fully defined for not only the SEE Region Grid Code purposes but also for the whole of the UCTE. The UCTE definitions to date are unclear, incomplete and therefore unsuitable for both technical and investment evaluation purposes.
7. It is necessary to expedite as much work as possible on the completion and/or progressing of ongoing SCADA/EMS projects. This will enable better control and better utilisation of the existing transmission facilities as well as opportunity trades across interconnectors.
8. In terms of settlement it is possible to manage balancing processes with spreadsheet type facilities for the initial REM. This will initially require some assumptions to be made for metering and load profiles.
9. Completion of metering projects is not absolutely essential for the initial REM and such projects can be progressed for completion for the final REM.
10. In terms of managing the Security and Quality of Supply as well as the integrity and stability of the SEE Region system in parallel operation with the UCTE it is essential that there is an organisation such as the EKC to carry out the necessary analytical load flow and stability calculations on a daily, weekly, monthly, seasonal and annual basis and to determine the transfer levels while coordinating the necessary generation and transmission outages. Failure to make such a provision will severely prejudice not only the security and quality of the supply in the SEE Region but will also have far reaching adverse consequences for the operation of the UCTE system.
11. A major weakness of the SEE Region utilities is the insufficient attention to the management of system voltage and provision of reactive power reserves. All utilities need to get more disciplined in this respect to prevent voltage collapse incidents. This process should also be managed and coordinated by EKC both across the Region and specifically on a zonal basis clearly making provision for sufficient reserves in each zone.
12. Although many of the utilities have not reported major congestion problems these are likely as the older generating plant is retired and new plant is constructed at new locations. In addition changes in

trading will also change the interconnection transfer patterns creating new transmission constraints. It is therefore important to facilitate the appropriate transmission investments to remove such constraints enabling economic operation of the SEE regional system.