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Complete GIS Report

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Generation and Transmission Main Report

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3 Generation and transmission study

3.1 Introduction

The main objective of the proposed study is to assist the EC, IFIs and donors in identifying an indicative priority list of investments in power generation and related electricity infrastructure from the regional perspective and in line with the objectives of REM in SEE. The study will identify priority investments in future generating capacity as well as main transmission interconnections between the jurisdictions over the next 15 years (2005 – 2020).

As stated in the ToRs, the analysis of alternative development options includes the preparation of three alternative generation expansion scenarios. The first scenario (Scenario A) consists of individual least cost plans for generating capacity expansion plans in each power system, i.e. utilities in each jurisdiction, without the benefits of regional cooperation. The second scenario (Scenario B) is an unconstrained least cost development plan, also for capacity expansion, for all power systems participating in the REM operating as a completely integrated regional power system. The second scenario corresponds to an ideal case in which no transmission or other system operation constraints limit an optimal generation dispatch in meeting the regional demand. Potential cost savings associated with such a scenario are:

- More efficient dispatch of generating units;
- Non-coincidence of peak loads;
- Lower spinning reserve requirements;
- More economical electricity generation;
- Higher reliability of system operation;
- Better management of hydro power plants and reservoirs;
- More economical maintenance scheduling;
- Reduced short-run marginal generation costs, etc.

Finally, the third scenario (Scenario C) studies, based on a detailed hourly market simulation for two years (2010 and 2015), the actual operating conditions in the REM based on the candidate capacity projects identified as regional priorities in the second (fully integrated) scenario, as well as the proposed regional transmission interconnections. This analysis indicates possible modifications to the coordinated development scenario based on specific requirements for balancing each power system in the REM. The modifications may include additional transmission capacities and/or new generation capacities that may come from the first scenario of individual system development.

Greater emphasis is placed on the development of Scenario C that leads to the recommendation of priority investment programmes in both generation and transmission. The analysis of Scenarios A and B provide an estimation of maximum savings that could be obtained under the extreme case of operating each of the power systems independently and within a fully integrated regional system without any physical or trade constraints. Under Scenario C, we attempt to find a realistic scenario, balancing all existing and future constraints.

For consistency purposes with prior investment studies done in the region, we use the WASP and GTMax models as stated in the ToRs. WASP is a computer model that evaluates least-cost capacity expansion programmes for generation over a 15-30 year planning period. GTMax provides detailed hourly simulations of complex electricity markets taking into account generation and transmission constraints. GTMax is used to perform detailed modelling of the electricity grid operated under REM conditions. It takes into account the transfer capabilities of the interconnection lines among the utility systems. GTMax is used to assist in the development and assessment of Scenario C. A series of runs is made for selected typical weeks in 2010 and 2015.

To further analyze the needs to expand or upgrade regional transmission interconnections, the results of the GTMax model are further tested in the PSS/E model. An agreement was reached with the SECI Transmission group so that they could run several cases. The PSS/E model is a very detailed model that analyses the basic functions of power system performance simulation work, namely:

- Data handling, updating, and manipulation;
- Power Flow;
- Fault Analysis; and
- Dynamic Simulation + Extended Term Simulation.

The GTMax results for the regional peak hour of 2010 and 2015 are used in the PSS/E model to evaluate the proposed transmission interconnections for 2010 and 2015. Details on the PSS/E model and the results are presented in Appendix 12.

The models are briefly described in the following section.

3.2 Computer Models

3.2.1 Wien Automatic System Planning Package (WASP-IV)

The goal of electric power systems expansion planning is to determine the optimal pattern of system expansion to meet the electricity requirements over a given period. WASP-IV helps find least-cost expansion plans for power generating systems for a look-ahead period of up to 30 years, within constraints specified by the utility planner. WASP-IV uses probabilistic estimation of production costs, the amount of energy not served, and system reliability parameters, together with a dynamic programming method of optimization, to compare the costs of alternative system expansion plans. Each possible sequence of power units added to the system (expansion plan) meeting the constraints specified by the user is evaluated by a cost function (the objective function) comprising capital investment costs, salvage value of investment costs, fuel costs, fuel inventory costs, non-fuel operation and maintenance costs, and the cost of the expected amount of energy-not-served (ENS).

WASP-IV measures system reliability with three indices: reserve margin, loss-of-load-probability (LOLP), and ENS. These reliability indices, plus the maximum number of thermal or hydroelectric units that can be added each year, are entered as user-specified constraints that an expansion plan must meet to be accepted. WASP-IV is comprised of the following eight modules.

- **LOADSY (Load System Description):** Processes information describing the peak loads and load duration curves for up to 30 years. The objective of LOADSY is to prepare all the demand information needed by subsequent modules.

- **FIXSYS (Fixed System Description):** Processes information describing the existing generating system. This includes performance and cost characteristics of all generating units in the system at the start of the study period and a list of retirements and fixed additions to the system. Fixed additions are power plants already committed to be built and not subject to change.

- **VARSYS (Variable System Description):** Processes information describing the various generating units to be considered as candidates for expanding the generating system.

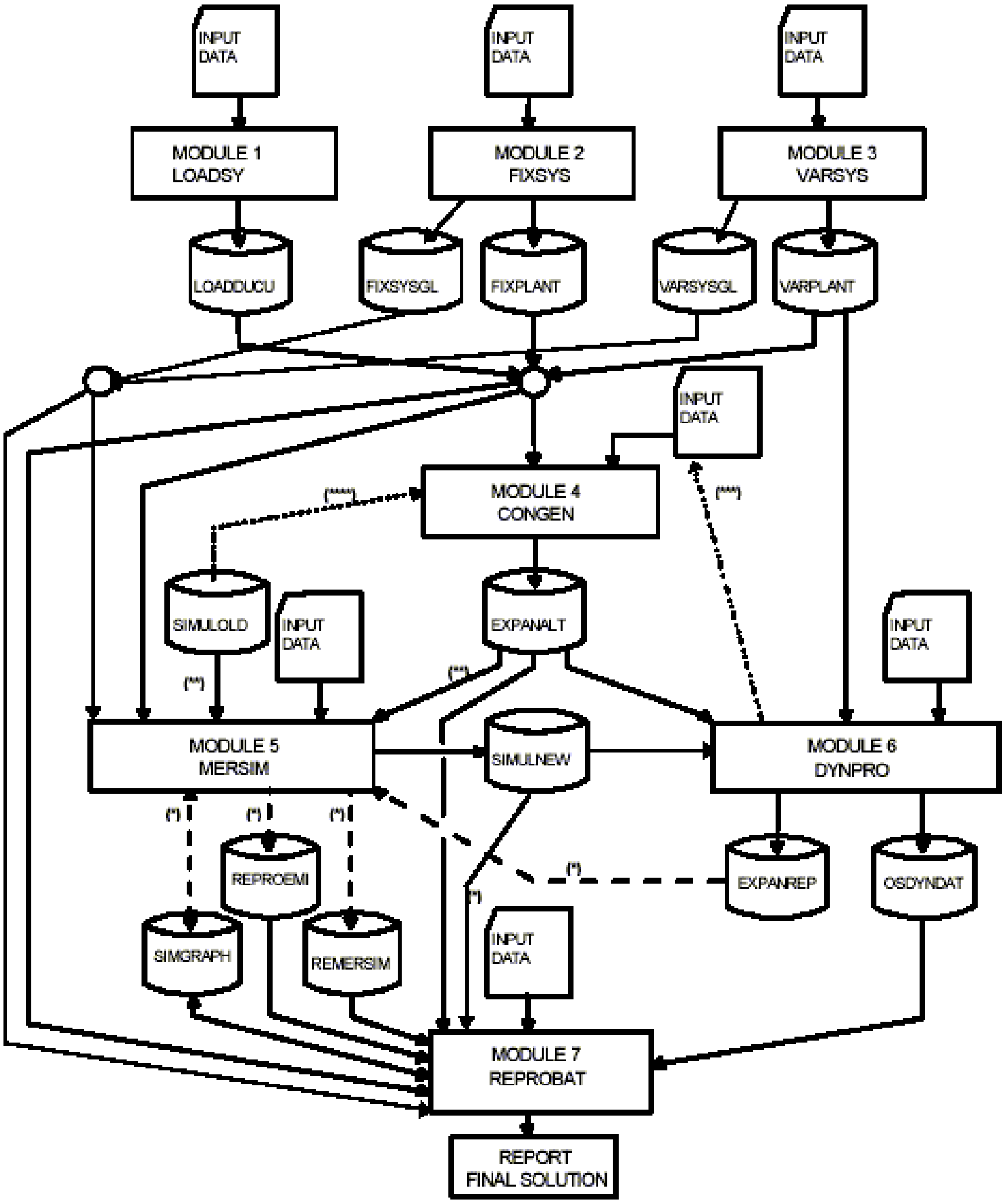
- **CONGEN (Configuration Generator):** Calculates all possible year-to-year combinations of expansion candidate additions that satisfy certain input constraints and that, in combination with the existing system, can adequately meet the electricity demand.

- **MERSIM (Merge and Simulate):** Considers all configurations put forward by CONGEN and uses probabilistic simulation of system operation to calculate the associated production costs, ENS, and system reliability for each configuration. The module also calculates plant loading orders, if desired, and makes use of all previously simulated configurations.

- **DYNPRO (Dynamic Programming Optimization):** Determines the optimum expansion plan as based on previously derived operating costs along with input information on capital cost, ENS cost, and economic parameters and reliability criteria.

- **REMERSIM (Re-MERSIM):** Simulates the configurations contained in the optimised solution. By providing a detailed output of the simulation, REMERSIM allows the user to analyze particular components of the production-cost calculation, such as unit-by-unit capacity factors for each season and hydroelectric condition.

- **REPROBAT (Report Writer of WASP in a Batched Environment):** Writes a report summarizing the total or partial results for the optimum or near-optimum power system expansion plan and fixed expansion schedules.



(*) FOR RESIMULATION OF BEST SOLUTION ONLY

(**) OMMIT FOR RESIMULATION OF BEST SOLUTION

(***) ITERATION PATTERN IF BEST SOLUTION STILL CONSTRAINED

(****) FOR CHECK OF CONFIGURATIONS ALREADY SIMULATED

Figure 1. Simplified Flow Chart of WASP-IV Computer Model

3.2.2 Generation and Transmission Maximization Program (GTMax)

The Generation and Transmission Maximization Program (GTMax), allows the simulation of a complex electricity market and operational issues, both for competitive and regulated environments. With GTMax, utility planners can maximise the value of the electric system taking into account not only each utility company's own limited energy and transmission resources but also firm contracts, independent power produer (IPP) agreements, and bulk power transaction opportunities for the group of interconnected systems on the region. GTMax maximises net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. The model does this while ensuring that market transactions and system operations are within the physical and institutional limitations of the power system.

Figure 2 presents the input and output modules of GTMax.

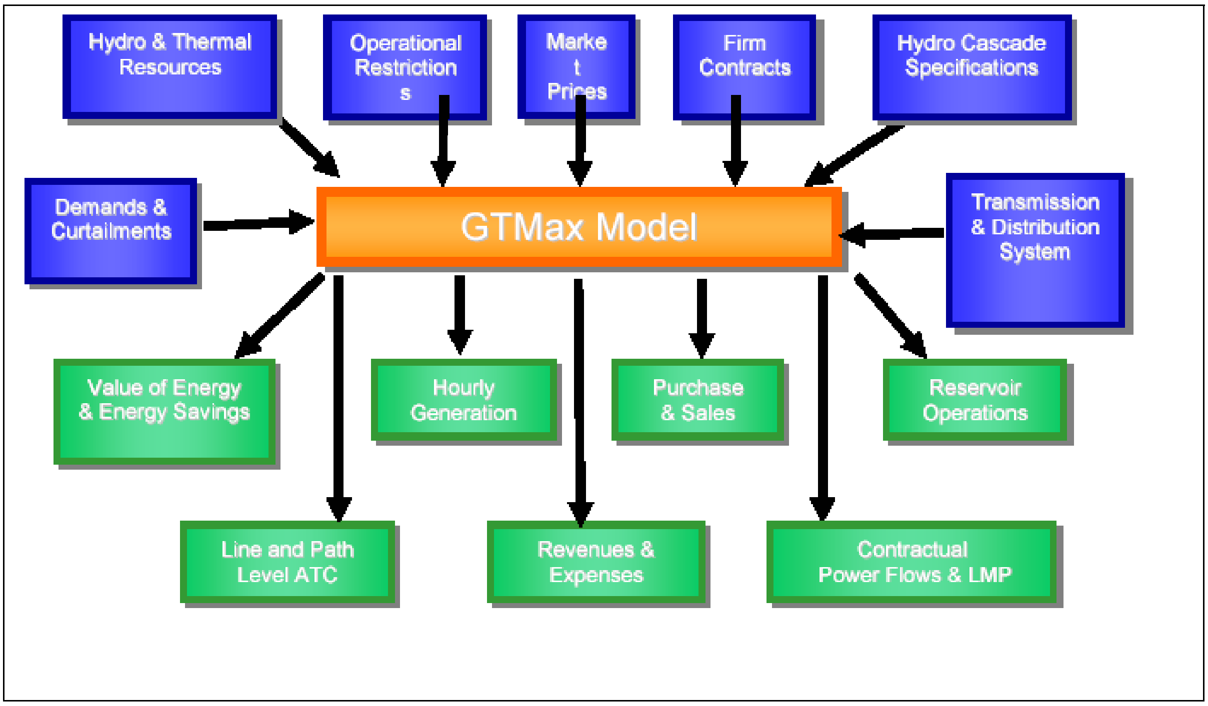


Figure 2. GTMax Input Information and Model Results

The GTMax analysis takes into account the topology of the electric power systems, interconnection transfer capabilities, chronological hourly loads, and the differences in the electricity generation costs in each of the utility systems. The programme simulates the dispatch of electric generating units and the economic trade of energy among utility companies using a network representation of the power grid. Generation and energy transactions serve electricity loads that are located at various locations throughout the simulated region. Links and transformers connect generation and energy delivery points to load centres. Electricity loads are satisfied, curtailed via contractual agreements, or not served due to a generator supply shortage or because of transmission limitations.

GTMax calculates market prices for electricity sales/purchases in different regions (market hubs) of the power network based on the capacity constraints of transmission inter-ties. The model simultaneously optimises transactions to minimise overall operating costs in the region. GTMax output includes: the units to be dispatched, how much power should be generated and sold on an hourly basis, when to buy and sell power on the spot market, the cost of alternative power plant operations, the incremental value of water, and the value of demand-side management programmes.

GTMax has a detailed representation of many different components of the power system. Nuclear, baseload thermal, cycling, and peaking power plants can all be characterised in the model. There is also a special representation for Combined Heat and Power (CHP) plants. The types of hydropower plants that can be simulated include storage units, run-of-river power plants, and pumped storage. Hydropower plants can also be specified in a cascade such that reservoir water levels remain within physical and institutional operating levels.

On the demand-side of the power equation, the GTMax model includes an hourly representation of [residential, commercial, and industrial] electricity demands at user-specified load centres. Demands that are served by the power sector are a function of electricity price. When the locational market price in the network reaches or exceeds a user-specified level, GTMax can simulate a Demand Side Management (DSM) programme for that region to reduce system loads.

The general topology of the regional network configured in GTMax for 2010 is shown on Figure 3.

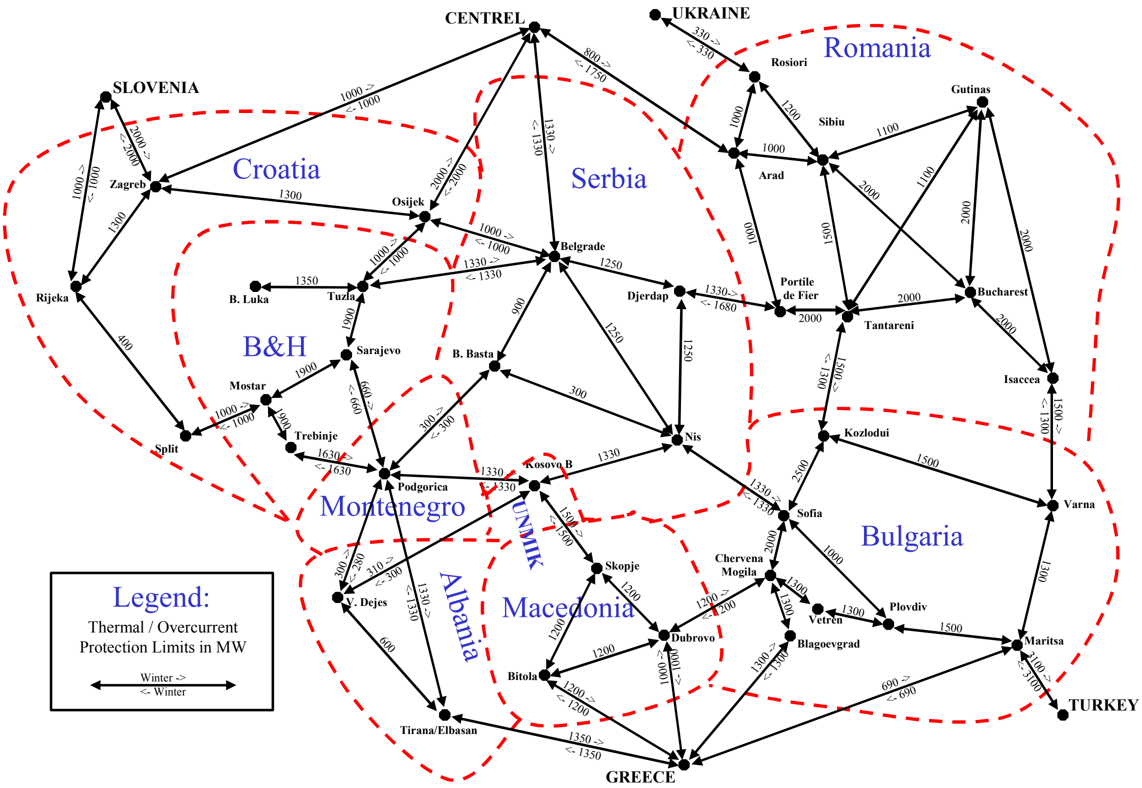


Figure 3. GTMax Regional Topology for 2010

The GTMax model requires several different types of data that defines the topology of a power system network and provides detailed information about link and node network components. An example of a hypothetical power system is shown in Figure 4.

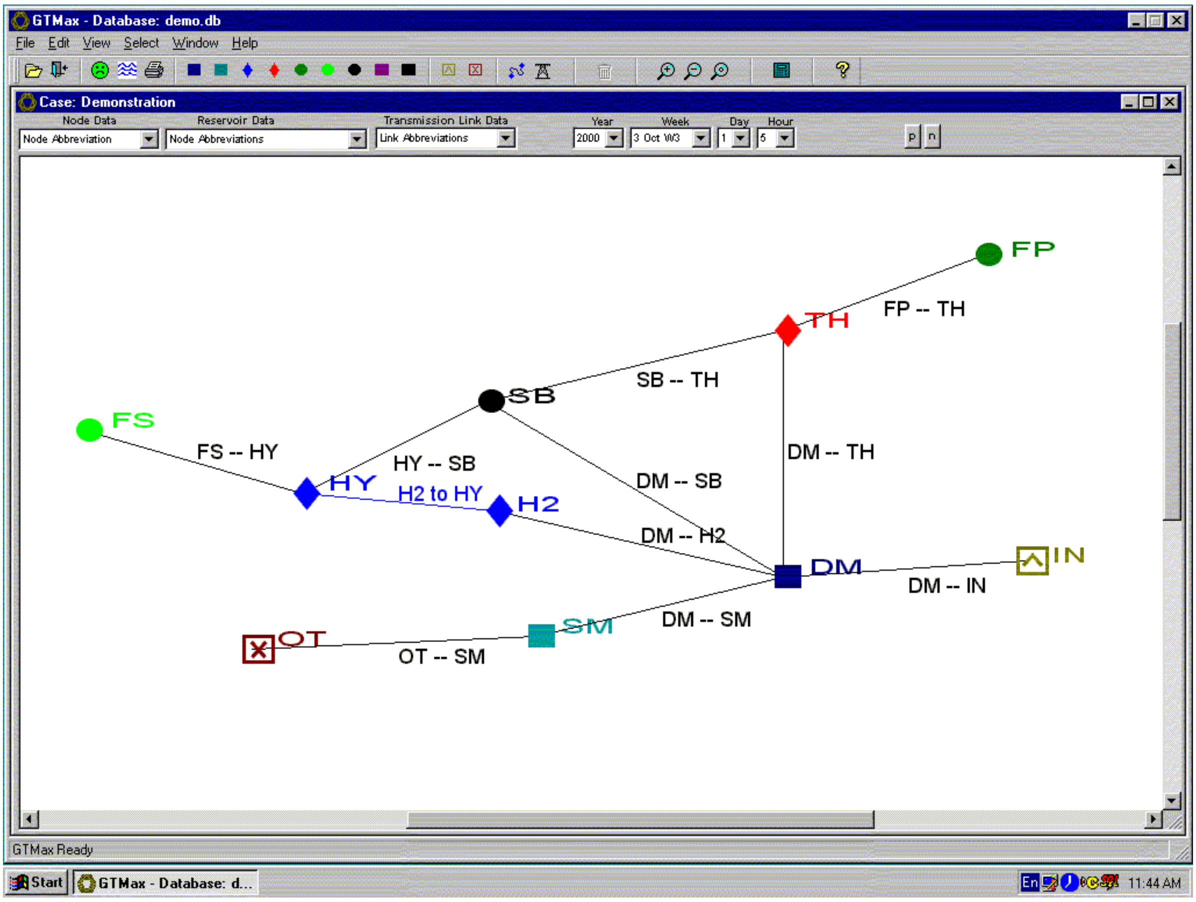


Figure 4. Hypothetical GTMax Power System

The following summarises the different node types that may be needed to represent an electric power system in the GTMax model.

3.2.2.1 Hydro Node 

The Hydro node represents a hydropower plant. It has numerous inputs including water-to-power conversion efficiencies and maximum and minimum generation levels.

3.2.2.2 Thermal Node 

The Thermal node represents a thermal power plant. It also has numerous inputs including maximum and minimum generation levels and weekly energy limits.

3.2.2.3 Demand Node 

The Demand node contains hourly electricity loads.

3.2.2.4 Purchase Contract Node 

The Purchase Contract node data input includes a step-function of purchase prices and quantities. It also has weekly and daily minimum and maximum delivery limits under a contract. A minimum hourly delivery schedule can be specified.

3.2.2.5 Sale Contract Node

This node represents a firm sales contract and has input variables that represent contract sales terms similar to the purchase node.

3.2.2.6 Spot Market Node

The main data input for this node are spot market prices.

3.2.2.7 Substation Node

This node does not have any data input forms. It is only used to connect nodes and is also used to compute regional market energy prices.

There are two types of links that are normally used in GTMax. Links that represent transmission lines (black lines in the topology) and links that connect reservoirs (i.e., cascade links that are blue in the topology). GTMax uses transmission lines to compute contractual power flows. Inputs include hourly energy transfer capabilities on links and associated line losses. There are also entries for hourly transmission costs or charges.

Cascade links include data inputs for downstream reservoir operations such as minimum and maximum reservoir elevation levels and limits on reservoir elevation changes over time. To make reservoir elevation calculations it is necessary to know how much a reservoir elevation will change when a unit of water is released from it. Typically, an average value between the minimum and maximum allowable elevation level is specified as an input to GTMax.

3.2.3 Description of PSS/E Model

The Power System Simulator for Engineering (PSS/E) model is a system of computer programs and structured data files designed to handle the basic functions of power system performance simulation work, namely:

- Data handling, updating, and manipulation;
- Power Flow;
- Fault Analysis;
- Dynamic Simulation + Extended Term Simulation; and
- Equivalent Construction.

Since its introduction in 1976, the PSS/E tool has become the most comprehensive, technically advanced, and widely used commercial program of its type. It is widely recognised as the most fully featured, time-tested and best performing product available in the market. The program employs the latest technology and numerical algorithms to efficiently solve networks large and small. PSS/E is comprised of the following modules:

PSS/E Optimal Power Flow (PSS/E OPF)

PSS/E Optimal Power Flow (PSS/E OPF) is a powerful and easy-to-use network analysis tool that goes beyond traditional load flow analysis to fully optimise and refine a transmission system. This task is achieved with the integration of PSS/E OPF into the PSS/E load flow program.

PSS/E OPF improves the efficiency and throughput of power system performance studies by adding intelligence to the load flow solution process. Whereas the conventional load flow relies on an engineer to systematically investigate a variety of solutions before arriving at a satisfactory solution, PSS/E OPF directly changes controls to quickly determine the best solution. From virtually any reasonable starting point, you are assured that a unique and globally optimal solution will be attained; one that simultaneously satisfies system limits and minimises costs or maximises performance.

PSS/E Balanced or Unbalanced Fault Analysis

The PSS/E Fault Analysis (short circuit) program is fully integrated with the power flow program. The system model includes exact treatment of transformer phase shift, and the actual voltage profile from the solved power flow case.

PSS/E Dynamic Simulation

PSS/E offers users uncompromising dynamic simulation capabilities. It models system disturbances such as faults, generator tripping, motor starting and loss of field. The program contains an extensive library of generator, exciter, governor, and stabiliser models as well as relay model including underfrequency, distance and overcurrent relays to accurately simulate disturbances.

The structure of the PSS/E model is illustrated in Figure 5.

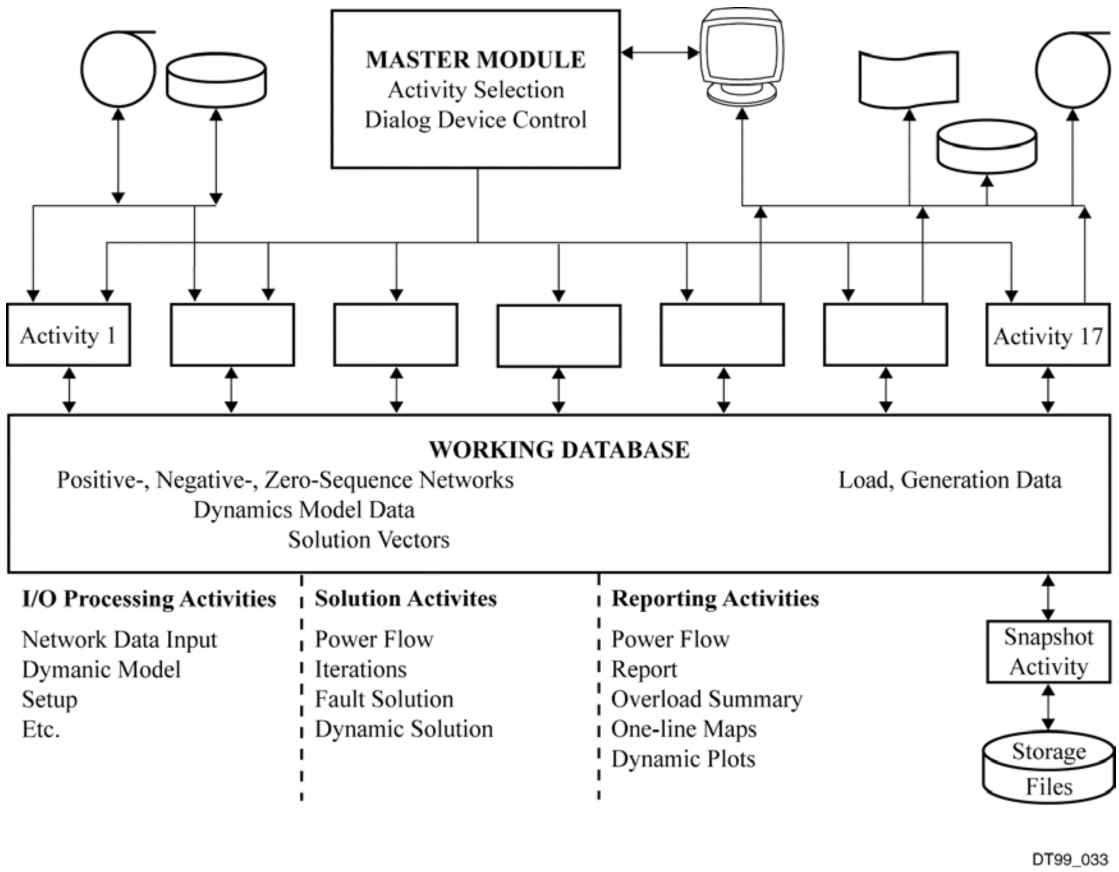


Figure 5. PSS/E Model Structure

3.3 WASP, GTMax and PSS/E Runs

3.3.1 Summary

The set of runs for WASP and GTMax identified below take account of the scenarios identified in the ToRs and the sensitivities identified during the first Consultative Workshop and first General Workshop. Our view is that they allow assessment of the position in each jurisdiction, enable the benefits of a regional market to be assessed, and focus on practical alternative scenarios within the constrained regional market (Scenario C) to demonstrate the robustness of the outputs. PSS/E runs were added to the Scenario C analysis and defined in collaboration with the South East Europe Cooperative Initiative (SECI) Transmission group.

3.3.2 Basis for runs

The main criteria for the WASP and GTMax runs are described below.

- All WASP runs will be performed over the planning period 2005-2020, and will include a probability distribution for wet, average and dry-year conditions for hydro plants in each run. Each run is made under a specific load forecast.

- Each GTMax run is performed for one specific week in 2010 or 2015, under a specific hydro condition: wet, average or dry. Each GTMax runs includes a detailed hourly optimization between generation and transmission. The power plant used in GTMax are obtained from the corresponding WASP runs.

- Under Scenario C, both WASP and GTMax models are run in parallel and it takes several iterations between the two models to obtain a final run.

The proposed WASP and GTMax runs are described below. As stated above, effort will be focused predominantly on Scenario C.

The details of the alternative import/export, real exchange rate, alternative rehabilitation scenarios and alternative nuclear expansion plan are discussed in Section 2.8 and Appendix 8.

Scenario A (Nine individual jurisdictions):

- WASP: Medium load demand forecast and most likely fuel price forecast (for all fuels) for each jurisdiction.

- GTMax: No runs.

- PSS/E: No runs.

Scenario B (One unrestricted region):

- WASP: There are three runs:

  - Medium load demand forecast and most likely fuel price forecast for all fuels.

  - Medium load demand forecast, most likely fuel price forecast for all fuels, and alternative rehabilitation plan (focusing on cost effectiveness of the rehabilitations proposed by the Utilities).

- GTMax: No runs.

- PSS/E: No runs.

Scenario C (One restricted region):

- WASP: There are ten runs as follows.

  - Medium load demand forecast and most likely fuel price forecast for all fuels;

  - Medium load demand forecast and most likely fuel price forecast for all fuels and forced hydro;

  - Low load demand forecast and most likely fuel price forecast for all fuels;

  - High load demand forecast and most likely fuel price forecast for all fuels;

  - Medium load demand forecast, high gas price forecast and most likely fuel price for all other fuels;

- Medium load demand forecast, most likely fuel price for all fuels, and full environmental compliance;

- Medium load demand forecast, most likely fuel price for all fuels and lower discount rate (7%);

- Medium load demand forecast, most likely fuel price forecast for all fuels, and alternative nuclear expansion plan (Belene unit 1 starting operation in 2012);

- Medium load demand forecast, most likely fuel price forecast, and alternative import/export plan (1,500 MW of net import for the period 2010-2020); and

- Medium load demand forecast, most likely fuel price forecast for all fuels, and a 15% increase in the construction costs of all new plant.

* GTMax: There are nine runs. Note that the peak week is defined as the week when the annual peak demand is expected to occur.

  - Medium load demand forecast, most likely fuel price forecast for all fuels, and average-year hydro conditions (4 weeks in 2010 and 4 weeks in 2015)

  - Medium load demand forecast, most likely fuel price forecast for all fuels, and wet-year hydro conditions (4 weeks in 2010 and 4 weeks in 2015)

  - Medium load demand forecast, most likely fuel price forecast for all fuels, and dry-year hydro conditions (4 weeks in 2010 and 4 weeks in 2015)

  - High load demand forecast, most likely fuel price forecast for all fuels, and average-year hydro conditions (Peak week in 2010 and 2015)

  - Low load demand forecast, most likely fuel price forecast for all fuels, and average-year hydro conditions (Peak week in 2010 and 2015)

  - Medium load demand forecast, high gas price forecast, most likely fuel price forecast for all other fuels and average-year hydro conditions (Peak week in 2010 and 2015)

  - Medium load demand forecast, most likely fuel price forecast for all fuels, forced hydro case, and average, dry and wet-year hydro conditions (Peak week in 2010 and 2015)

  - Medium load demand forecast, most likely fuel price forecast for all fuels, alternative nuclear expansion plan, and average-year hydro conditions (Peak week in 2010 and 2015)

  - Medium load demand forecast, most likely fuel price forecast for all fuels, alternative import/export plan, and average-year hydro conditions (Peak week in 2010 and 2015)

- PSS/E: There are fourteen runs as follows.

  - GTMax 2010 peak hour output under medium load demand forecast, most likely fuel price forecast for all fuels, and for dry, average, and wet hydro conditions (under 2010 topology)

  - GTMax 2015 peak hour output under medium load demand forecast, most likely fuel price forecast for all fuels, and for dry, average and wet hydro conditions (under 2010 and 2015 topology)

  - GTMax 2010 peak hour output under high load demand forecast, most likely fuel price forecast for all fuels, and average hydro conditions (under 2010 topology)

  - GTMax 2015 peak hour output under high load demand forecast, most likely fuel price forecast for all fuels, and average hydro conditions (under 2010 and 2015 topology)

  - GTMax 2010 peak hour output under medium load demand forecast, most likely fuel price forecast for all fuels, alternative import/export plan, and average hydro conditions (2010 topology)

  - GTMax 2015 peak hour output under medium load demand forecast, most likely fuel price forecast for all fuels, alternative import/export plan, and average hydro conditions (2010 topology)

3.4 Candidate plant

We have identified a number of candidate plant that could be required to meet the growing demand of the region over the next twenty years. These are of two types:

- Specific plant: these are plant that have already been identified as potentials for development. Their size, fuel type and location are known and there are estimated costs available. In general, feasibility studies have been undertaken to justify the potential for such plant. We summarise the data regarding specific candidate plant in each country in Appendix 8.

- Generic plant: these plant represent plant of typical size and fuel combinations for the region and allow consideration of new plant that have not yet been identified. In particular, generic plant are typically required to meet demand growth, in the later part of the study period.

The total number of candidate plant that can be considered within the WASP simulations (the VARSYS module described above) is limited. A maximum of 12 different types of candidate thermal plant can be used (11 if pumped storage is also considered a candidate). The number of units in each plant is not limited. For hydro, two types of plant can be used (peak and run-of-river), each one composed of up to 30 projects and one pumped storage plant type with up to 30 projects. This restriction also emphasises the importance of using generic plant.

For the existing and known power plant to be rehabilitated or upgraded, the number of plants accepted by WASP is also limited. The total number of plant in the Fixed System (FIXSYS module described above) is limited to 73 plants (88 minus the 15 reserved for candidates plants). If a decision has been made to rehabilitate or upgrade an existing plant that will therefore have most likely new technical and economic characteristics once rehabilitated, the "new" plant will use one of the 73 slots available. As in the VARSYS module, the number of units in each plant is not limited, however.

Plant were also grouped by fuel types and the number of fuel types and price forecasts for oil, gas, lignite, coal, nuclear, etc. is limited to 10 for all existing and candidate thermal plant.

For Scenarios B and C (regional scenarios), the analysis of candidate hydro and pumped storage plant will not be a problem since we have up to 30 projects for each type. We will need however to regroup existing and known thermal plant to be rehabilitated with same (or similar) parameters within each of the considered jurisdictions to remain below the maximum number (73) of plant that can be included in the FIXSYS module. A more difficult task will be to limit the total number of candidate plant throughout the region to 11, especially if we want to include the analysis of potential rehabilitation of existing plant that have not yet been economically justified. The results to be obtained under Scenario A where we have more flexibility in running WASP will help us select the best candidate alternatives for the region.

3.4.1 Generic plant

- Our candidate generic plant are derived from consideration of a number of factors, each of which is discussed in turn. Based on this discussion, and consideration of economic, technical, regulatory factors, the range of GIS plant size/type/fuel combinations has been reduced to a family of candidates felt to be appropriate for the region over the timescale of the study.

- The impact of the Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants - LCPD (OJ L 309/1, 27.11.2001) on the type of new plant was taken into account. Although this GIS study does not directly address the environmental aspects, the related *Study on the Implications for Investments in Environmental Protection* is ongoing, with the objective of analysing the needs of new plants in the region assuming EU environmental compliance and requirements. In particular, it takes into account the aspiration of SEE jurisdictions of EU accession. The Council Directive 96/61/EC of 24 September 1996 concerning integrated pollution prevention and control -IPPCD (OJ L 257, 10.10.1996) is used in conjunction with the LCPD and other related EU regulation to address "the best available technologies" to meet EU adopted emission limit values (ELV) for SO_2, NO_x and dust. The LCPD was followed to select suitable technologies to meet ELV until 2016. The extra costs associated with such technologies are covered within the generic plant costs given.

- National obligations under the United Nations Framework Convention on Climate Change - UN FCCC (1992) and the Kyoto Protocol (1997) were taken into account. The Kyoto Protocol sets targets for each of the "developed country" parties and "transition economy" parties with a view to reducing their overall emissions of the six main GHG's (CO_2 is the most important one). The EU objective is to stabilise concentrations of greenhouse gases in the atmosphere at a level that will not cause unnatural variations in the Earth's climate. In the short to medium term (2008-12) its aim is to reduce greenhouse gas emissions by 8% compared with 1990 levels. In the longer term (by 2020) the objective is to reduce global emissions by approximately 20-40%.

- The Convention on Long-range Trans-boundary Air Pollution (1979) and eight related protocols, all adopted by the United Nations Economic Commission for Europe parties (UN ECE), also have impacts on planning and constructing of new plants in the SEE region.

- Although the importance of oil-fired plant is reducing in Western Europe, the lack of significant volumes of gas in the SEE region means that, in the short-to-medium-term, combined cycle plant are likely to be oil-fired rather than gas-fired. It is common practice for combined cycle plants to have the capability of dual firing of oil and gas. However due to the higher cost associated with fuel oil and higher Nox, CO_2 and SOx emission concentrations it is the case that oil is often only used as a standby fuel. There are only marginal differences in efficiencies between the two fuels.

- Nuclear plant are typically much larger than those with other fuels. In addition, approval for nuclear plant tends to be a long process, with significant risks of delay. Particularly in Central and Eastern Europe, there have been concerns over plant safety, adequacy of decommissioning plans and funds and costs. Taking all these factors into consideration suggests that there is little justification for a generic nuclear plant in the SEE region. Where a nuclear plant is a realistic prospect for development, it was included as a specific candidate plant.

- Renewables (excluding hydro power): We recognise that there are likely to be a number of renewable plant developed in many of the jurisdictions covered by the study over the next 15 years. However, any of these developments will be small-scale, or will operate sporadically and, as such, are below the radar of this project. The high cost of initial investments represents a limiting factor in the expansion of renewables and it is likely that, in order to overcome this obstacle, special incentive programmes would be required including a financial and or financing component. On this basis, we exclude renewables from our list of candidate plant.

- The concept of a generic hydro plant is more complex, since the cost of hydro schemes, the size and capacity of the plant are dependent on specific locations. We also assume that new storage hydro schemes would be used for peak energy. Only specific hydro schemes are considered as candidate plant.

- Plant size: The GIS study considers both individual jurisdictions and the SEE region as a whole. As a consequence of this, we have considered two alternative plant sizes. Our conclusions on size have assessed the relative efficiencies of plants of varying sizes, the cost of producing electricity (which will be of importance once a regional market is in place), and the relative costs of developing two small plant as opposed to one large plant given growth in demand. The sizes are based on practical considerations of current technology suitable for the region, demand growth and transmission capacity. Whilst none of these necessarily limit the building of large-scale plant, the combination leads to the view that medium-size plant are most likely.

- The size of plant assumed for generic candidates would not generally be expected to increase the loading of the high voltage transmission network to the point where major reinforcement would be required for individual plant, except for a transmission interconnection between the plant and the national grid. However, the implementation of clusters of plant or situations where the building of new plant significantly changes power flows because of pricing (or other factors), could require transmission reinforcement in the national grid. This is analysed under Scenario C.

- We recognise that there is uncertainty over the level of capital costs associated with each plant type that might be built in the region, and address this within one of the sensitivity runs under Scenario C. Uncertainty can be influenced by factors such as the percentage of costs in local currency and foreign currency (typically $ or €), delays leading to cost overruns, geographical conditions at a specific site and commercial conditions such as cost of labour and materials. Our assessment is based on the uncertainty over the "cost of technology", based on review of data from a range of sources. Where robust feasibility studies have been undertaken, it is possible to reflect some of these uncertainties in a specific capital cost for a project.

From these deliberations we have developed the following list of generic candidate plant:

3.4.1.1 *Super-Critical Pulverised Fuel Plant*

- For this scenario the generation cycle uses pulverised fuel (PF), either imported high rank coal or domestic lignite.

- The technology is an extension from sub-critical power plants, with increased pressure and temperatures observed through reheating and superheating of the steam and the inclusion of high-pressure steam turbines.

- Super-critical technology can be applied to other combustion technologies, but for this case, the most technically recognised, and commercially viable exploitation has been considered.

- Two sizes of plant – 500MW and 600MW have been included for imported coal, with 300MW, 500MW and 600MW included for lignite.

- Low milling costs and minimal variation in fuel composition and rank weigh on the side of high rank, imported coal for this technology, with lignite use projected to be commercially available from 2010.

- Variations in capital costs may be up to 35%.

3.4.1.2 *Sub-Critical Pulverised Fuel Plant*

- These plants would only be run on lignite, and have the benefit of being the most established of the power generation technologies.

- Still operating with pulverised fuel, but at lesser conditions, an overall drop in efficiency of approximately 4% is observed compared to super-critical plant, but with established technology allowing better use of low ranking coals.

- Two sizes of plant – 300MW and 500MW have been included.

- Variations in capital costs may be up to 25% for the smaller plant and up to 35% for the larger plant.

3.4.1.3 *Circulating Fluidised Bed Plant*

- Circulating fluidised bed generating plant is commercially available to 250MW, with 300MW plant becoming available in the next 5 years. This, coupled with hot-gas cleaning will allow the technology to compete with PF plants with flue gas-desulphurisation (FGD).

- More suited to low ranking coals than PF plants, fluidised beds have the flexibility to operate on a wider variation in the fuel quality.

- Two sizes of plant – 150MW and 300MW have been included.

- Variations in capital costs may be up to 25%.

3.4.1.4 *Combined Cycle Gas Turbine Plant*

- Combined cycle gas turbine (CCGT) stations are the most efficient of the plants considered, with the least amount of local fabrication required.

- These plants can be operated on natural gas or distillate oil, though the gas turbine will not allow much variation on the composition of either.

- Single shaft, 150MW, 300MW and 500MW units have been included.

- Variations in capital costs may be up to 15% for the 150MW and 300MW plant and up to 25% for the 500MW plant.

3.4.1.5 *Open Cycle Gas Turbine Plant*

- Open cycle gas turbine (OCGT) stations have a simple generation cycle with a gas turbine operated without heat recovery and steam turbine generation equipment.

- This type of plant is normally used for “peaking” or “mid-merit” operations to support electricity supplies during periods of high demand. Similarly to CCGTs, these plants can be operated on natural gas or distillate oil.

- 50MW and 100MW units have been included.

- Variations in capital costs may be up to 25%.

3.4.1.6 *Nuclear Plant*

- Nuclear fuelled power plant have been included as an alternative to conventional combustion plant, in a sensitivity run.

- Two sizes of plant have been considered – 600MW and 1000MW.

- Variations in capital costs may be up to 20%.

A comparison of these generating plants is shown in Table 1 and Table 2.

Table 1: Generic Plant Characteristics

Plant	Installed Capacity (=Plant Size) MW	Internal Energy Consump-tion %	Max sent-out operating capacity MW	Min. sent-out operating capacity MW	Heat Rate at min operating capacity kcal/kWh	Heat Rate at max operating capacity kcal/kWh	Construction period years
Coal Super-Critical	500	8	470	250	2462	2230	4
	600	8	564	300	2450	2190	4
Lignite Sub-Critical	300	10	275	150	2819	2530	4
	500	8.5	450	250	2707	2430	4
Lignite Super-Critical	300	10	270	150	2600	2350	from 2010
	500	9	450	250	2462	2210	from 2010
	600	8.5	550	275	2304	2140	from 2010
Lignite CFBC Sub-Critical	150	10	135	75	2562	2300	4
	300	10	270	150	2543	2283	4
CCGT Single Shaft	150	4	144	88	1917	1617	2
	300	4	288	150	1680	1560	2.5
	500	4	480	250	1888	1753	3
OCGT Single Shaft	50	4	48	29	2715	2219	1.5
	100	4	96	57	2747	2248	1.5
Nuclear	600	10	540	300	N/A	2700	8
	1000	8	925	700	N/A	2672	6

Table 2: Generic Plant Characteristics (Continued)

Plant	Installed Capacity (=Plant Size) MW	FOR %	MOR %	Variable O&M cost €/MWh	Fuel Type	Plant Eff% nett	Fixed O&M cost €m/ year	Capital cost €m	Capital cost €/KW
Coal Super-Critical	500	6	13	1.1	Imported coal	38.5	9.4	454	908
	600	6	13	1.1		38.5	11.2	544	907
Lignite Sub-Critical	300	5	11	1.3	Local lignite	33.5	10.2	304	1013
	500	6	13	1.3		35.0	12.6	499	998
Lignite Super-Critical	300	5	11	1.7		37.5	10.8	354	1180
	500	6	13	1.7	Local lignite	39	14.8	536	1072
	600	6	13	1.7		39.5	16.7	612	1020
Lignite CFBC Sub-Critical	150	9	4	1.3	Local lignite	36	5.5	179	1195
	300	10	5	1.0		36	10.3	324	1080
CCGT	150	5	5.8	2.2		51	3.6	96	642

Plant	Installed Capacity (=Plant Size) MW	FOR %	MOR %	Variable O&M cost €/MWh	Fuel Type	Plant Eff% nett	Fixed O&M cost €m/ year	Capital cost €m	Capital cost €/KW
Single Shaft	300	5	5.8	1.3	Natural gas	53	4.0	174	579
	500	5	4	1.3		52	5.7	241	483
OCGT Single Shaft	50	5	4	7.2	Natural gas	33	0.5	17	341
	100	5	5	4.4		34	0.7	30	297
Nuclear	600	8	16.4	4.9	Nuclear	32.0	37.6	1024	1707
	1000	10	16.4	4.9		32.2	56.1	1564	1564

3.4.1.7 *Assumptions underlying the generic candidate plant*

- Quoted output values and corresponding figures are used to predict the values for the nominated power plant sizes.
- Unless specified the Internal Energy Consumption is derived from the kW_{nett} output under maximum operating conditions.
- Minimum sent-out operating capacity is specific to a plant's generating arrangement i.e. number and sizes of generating units in a plant. It has been assumed that thermal plant can operate to 50% of capacity including CCGT.
- Heat rates at Minimum Capacity are calculated for sub-critical lignite plants. A similar loss in efficiency is extrapolated to other coal and lignite schemes. No adjustments due to regional variation in the calorific value of coal are made.
- Where a single heat rate figure for plant is stated for a plant, it is assumed that this is nominated for the Heat rate at Maximum Capacity. No adjustment due to regional variation in the calorific value of coal is made.
- Where variation in construction times is observed, a value reflecting the modal value is taken.
- Where variation in the Forced Outage Rate is observed, a conservative view is taken to reflect variation in maintenance practices for coal plant.
- Where variation in the Maintenance Outage Rate is observed, a cautious view is taken to reflect variation in maintenance practices for coal plant, and for plant larger than 300MW the value is scaled up to accommodate increased inspection requirements.
- The variable O&M rate is taken from sources where some adjustment is made for local labour rates. Where there is variation, the rate observed in countries of similar geographical locations is preferred. Where no differentiation is made with respect to the size of the plant, it is assumed that the labour rate will not

vary to any great extent and therefore a similar rate is applied. The variable O&M rate does not include fuel costs.

- Plant efficiencies are quoted at the 'nett' efficiency, excluding plant power requirements. Where the value observed is 'gross' a 2% loss in performance is assumed.

- Fixed O&M fees are calculated from $/kW and % availability figures (generally 84 – 85% for coal /lignite plants, 90% for CCGT and 70-75% for nuclear plants). Availability is assumed to be the total of forced and maintenance outages.

- Capital costs are estimated as €m and €/kW. Capital costs reflect projected values for EPC contact. No additional capital is added to allow for additional cost of electrical connections. The cost of finance through the construction period is ignored.

- Capital costs are escalated at an assumed inflation of 4% from date of origin to January 2005.

- Currency conversion of 1$ = 0.8375€, based on average of last calendar year.

3.5 Fuel costs

This section of the report covers the assumptions made in the simulations on the cost of fuel over time and within each of the jurisdictions. We consider lignite, coal, oil and gas as candidate fuels. For gas, we outline three alternative prices to allow consideration of fuel substitution. Where appropriate, we distinguish between local and imported fuels. The cost of nuclear fuel is only discussed for those countries with access to nuclear plant. Unless indicated, all costs are expressed in constant 2005 price levels.

3.5.1 Lignite

Our key assumption is that lignite will be sourced locally. There may be the potential for within-region imports during the latter part of the GIS study period, but this is only likely to apply to Montenegro and Macedonia. There is not a liquid market for lignite as it is not economic to transport it. The costs of extraction are the main cost that utilities need to cover, since lignite power plant are generally co-located with their lignite mine. Although there may be cost differentials between different mines, based on the ease of extraction, for this study a single cost is used for candidate plants. Where information is available on cost of lignite for existing plant, this is used. Imports from Greece are also a possibility for some jurisdictions.

Predicting future forecast prices for lignite is problematic in that it has no market value and prices should be purely related to extraction costs. In this respect, it might be expected that more efficient means of production would lead to reduced costs. On the other hand, scarcer resources, additional environmental mitigations, and more difficult extraction might lead to increasing costs. The combination of these factors leads to a good case for assuming lignite costs will remain constant. Examination of the ESTAP report [6] module G shows that production costs, dependent on scenario, either remain level or go down between 2001 and 2015. Indeed, there are significant variations year by year dependent on opening of new mines and consequent high capital investment in specific years. There is no justification for linking lignite prices to oil prices and we believe that a fair estimate of lignite prices is to assume that they remain constant throughout the study period.

The rational underlying our assumptions for each of the jurisdictions is summarised below:

- Albania: Lignite reserves are estimated at 772 million tonnes. Annual production is small and is consumed domestically for home and commercial heating and the small volumes of thermal generation. For local lignite power stations to be built, Albania would need to increase its lignite mining output. However, due to high production costs, poor coal quality and difficult mining and geological conditions it would be unlikely that it could feasibly increase output. It is hence the case that lignite fuelled power stations are not considered for Albania.

- Bosnia & Herzegovina: There are lignite reserves. Prices for domestic lignite have been provided by EPBiH and EPRS. A mean value has been used in the table below.

- Bulgaria: Lignite reserves are approximately 2.5 billion tonnes. Prices for the GIS study are based on the EER report [9].

- Croatia: There is no indigenous lignite. We assume that no lignite plant will be built in Croatia and no cost assumptions are made.

- FYR Macedonia: there are lignite reserves but these are limited. The Trans Balkan Power Line Report [12] quotes a price of €1.15/GJ ($1.42/GJ) for domestic lignite. Following the potential rehabilitation of the Bitola 2 TPP around 2015, there would be insufficient reserves from the current source to supply the plant. The most likely source for imported lignite would be from Greece, and we propose to use a price quoted from The Trans Balkan Power Line Report [12] to represent the cost of imported lignite from 2015 in constant 2005 prices. However, in practice, it is most unlikely that a plant based on the use of imported lignite would be given serious consideration.

- UNMIK: The production at the local lignite mines allows a competitive supply of fuel to power plant compared to international fuel sources and energy prices. The estimated reserves of around 10,000 million tonnes represents one of the richest lignite sources in Europe. The ESTAP report [6] provides a local lignite price.

- Montenegro: There are lignite reserves in Montenegro. EPCG has advised a cost of lignite.

- Romania: The Road Map [29] states that there is at least 50-70 years worth of lignite from existing mines at an annual production rate of 30-35 million tonnes from open pit mines. There are also underground mines, but these are less viable and many are likely to close in the future. The National Company of Lignite [Oltenia Tg.Jiu] has advised that the cost of lignite is equivalent to €2.34/GJ. This seems high compared to the other two sources of prices, the Romanian Electricity & Heat Regulatory Authority (ARNE) quotes a price equivalent to 1.61€/GJ. The Road Map [29] quotes a 2010 price forecast for lignite equivalent to 1.43€/GJ. In this study a lignite price of 1.52€/GJ is assumed for Romania.

- Serbia (excluding UNMIK): There are lignite reserves in Serbia. EPS has advised a cost of lignite.

Table 3: Assumed lignite costs

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	**2010**	**2015**	**2020**	**2005**	**1010**	**2015**	2020
Lignite								
Albania	-	-	-	-				
Bosnia & Herzegovina	1.71	1.71	1.71	1.71				
Bulgaria	0.88	0.88	0.88	0.88				
Croatia	-	-	-	-				
Unmik	0.62	0.62	0.62	0.62				
FYR Macedonia	1.34	1.34	-	-			1.66	1.66
Montenegro	2.44	2.44	2.44	2.44				
Romania	1.52	1.52	1.52	1.52				
Serbia (excluding Unmik)	1.34	1.34	1.34	1.34				

3.5.2 Hard coal

Table 4 shows world coal prices over the last 15 years taken from the BP Statistical Review [33]. It is most likely that hard coal imports into the region would follow a similar trend to the price figures given for North Western Europe. Figure 6 shows a graphical trend of hard coal price for North Western Europe from 1989 to 2003. The data does not exhibit a definitive upward nor downward trend in price. Future forecast prices for American coal were taken from the American Energy Outlook [34] and are shown in Table 5. The forecast shows that coal prices will remain stable up until 2025. It is assumed for the countries in this study that imported hard coal costs will remain stable up until 2020.

Table 4: Historical Coal Prices

Prices US dollars per tonne	**Market Price (basis Northwest Europe)***	**Price Price of US coal receipts at steam-electric utility plants**	**Japan coking coal import cif price**	**Japan steam coal import cif price**
1989	42.08	33.29	58.68	48.86
1990	43.48	33.33	60.54	50.81
1991	42.80	33.06	60.45	50.30
1992	38.53	32.23	57.82	48.45
1993	33.68	31.57	55.26	45.71
1994	37.18	30.75	51.77	43.66
1995	44.50	29.85	54.47	47.58
1996	41.25	29.19	56.68	49.54
1997	38.92	28.79	55.51	45.53
1998	32.00	28.31	50.76	40.51
1999	28.79	27.46	42.83	35.74
2000	35.99	27.13	39.69	34.58
2001	39.29	27.54	41.33	37.96
2002	31.65	28.33	42.01	36.90
2003	42.52	28.62	41.57	34.67

Figure 6: Graphical Representation of Coal Price Trend in North West Europe

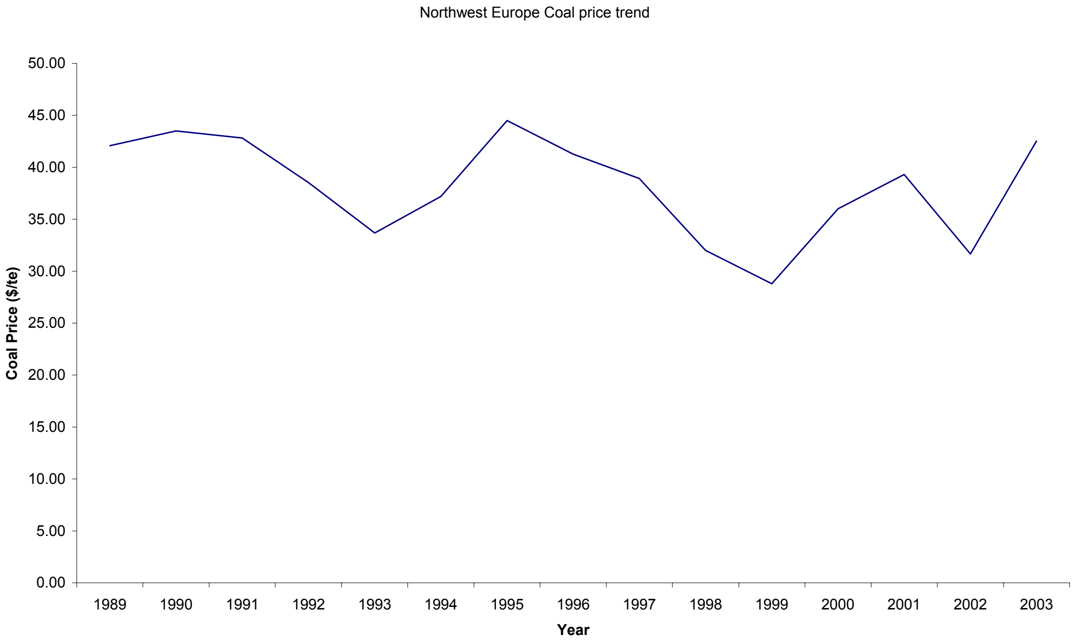


Table 5: American Energy Outlook Forecast Prices

Projection	2002	AEO2004 Reference	AEO2004 Low economic growth	AEO2004 High economic growth	Other forecasts EVA	Other forecasts Hill & Associates
			2015			
Average delivered price to electricity generators						
(2002 dollars per short ton)	25.96	24.34	23.17	25.10	NA	21.82 [c]
(2002 dollars per million Btu)	1.26	1.22	1.16	1.25	NA	1.08 [c]
			2020			
Average delivered price to electricity generators						
(2002 dollars per short ton)	25.96	24.01	22.87	25.03	NA	21.08 [c]
(2002 dollars per million Btu)	1.26	1.20	1.15	1.24	NA	1.04 [c]
			2025			
Average delivered price to electricity generators						
(2002 dollars per short ton)	25.96	24.31	22.75	26.29	NA	NA
(2002 dollars per million Btu)	1.26	1.22	1.14	1.30	NA	NA

A common import price for hard coal will be used for all of the countries covered in the study. Individual transportation and storage costs are likely to be slightly different for each country, however in the many reports reviewed whilst conducting this study, including the Albanian Decon report [35] and the Kosovo ESTAP report [6], a transportation and storage cost of $15/te was standard practice.

Two sources of information were received for the import price of coal into the region. The Romanian import price was supplied by the Romanian Ministry and gave a price of $60/te which included $15/te for transportation and storage costs. Assuming a gross calorific value of hard coal to be 26.8GJ/te (as used in the Albanian Decon

Report [35]) this gives a price equivalent to 1.88€/GJ. The Bulgarian utility, NEK supplies a price of 1.75€/GJ.

These prices seem relatively high compared to the 2003 price given for hard coal in North West Europe in the BP Statistical Review [33]. This represents a price equivalent to 1.41€/GJ. For the purpose of this report a hard coal price is taken as the average of the three prices obtained. This works out to be 1.68€/GJ.

There are some natural supplies of hard coal within the region however these local sources of hard coal are more expensive than imported coal due to the small scale of mining in the region and the age and efficiency of the mining equipment used. This is backed up by prices supplied by the Bosnian utilities EPRS and EPBiH and Romanian mining company Compania National a Huilei Petrosani.

The rational underlying our assumptions for each of the jurisdictions is summarised below:

- Albania: There are no significant hard coal resources, meaning that any future coal-fired station would need to run on imported coal. Coal would probably be imported via an Adriatic seaport (eg Durres or Vlore) and fuel via this route would be suitable for all existing generation sites except Korce which is located 900m above sea-level.
- Bosnia & Herzegovina: there are natural resources of brown coal.
- Bulgaria: hard coal reserves are approximately 200 million tonnes of sub-bituminous coal.
- Croatia: there are negligible reserves of coal, with minimal coal production.
- FYR Macedonia: There are no significant resources of hard coal, therefore and coal-fired plant would need to operate using imported coal.
- UNMIK: there are negligible quantities of hard coal. Given the large reserves of lignite and the interconnections with the power systems of surrounding jurisdictions, it is unlikely that imported coal would be an economic alternative. The GIS study assumes that no candidate plant would operate using imported coal.
- Montenegro: There are no sources of hard coal and there are no future plans to import hard coal into the country. The GIS study assumes that no candidate plant will operate using imported coal.
- Romania: around 3.5 million tonnes of domestic hard coal are produced annually, which is assumed to be constant to 2015 and beyond.
- Serbia (excluding UNMIK): There are no sources of hard coal and there are no future plans to import hard coal into the country. The GIS study assumes that no candidate plant will operate using imported coal.

Table 6: Assumed hard coal costs

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Coal								
Albania	-	-	-	-	1.68	1.68	1.68	1.68
Bosnia & Herzegovina	2.14	2.14	2.14	2.14	1.68	1.68	1.68	1.68
Bulgaria	-	-	-	-	1.68	1.68	1.68	1.68
Croatia	-	-	-	-	1.68	1.68	1.68	1.68
Unmik	-	-	-	-	-	-	-	-
FYR Macedonia	-	-	-	-	1.68	1.68	1.68	1.68
Montenegro	-	-	-	-	-	-	-	-
Romania	2.37	2.37	2.37	2.37	1.68	1.68	1.68	1.68
Serbia (excluding Unmik)	-	-	-	-	-	-	-	-

3.5.3 Gas

Most gas used in SEE originates from Russian gas fields and is delivered in pipelines through Ukraine. In SEE, small quantities of gas are produced in Serbia, in Croatia and some larger volumes in Romania. Previous gas production in Albania has almost stopped due to depletion of the gas fields.

Figure 7 is taken from the Kosovo ESTAP report [6] and shows current and some proposed gas pipelines within the region.

In estimating gas prices we assume, and discuss below, that the gas prices directly follow oil price trends. Two gas price scenarios are considered based on reference and low oil price scenarios. Oil Price Forecasts have been taken from the 2004 American Energy Outlook [34], which compares forecasts from a number of sources and provides reference and low oil prices, representing "best estimates". It should be noted that there is close agreement between the 2003 and 2004 forecasts, shown in Table 7 together with explanatory text, describing the studies they analysed.

Table 7: American Energy Outlook 2004 Forecasts for World Oil Prices (2002 dollars per barrel)

Forecast	2005	2010	2015	2020	2025
AEO2003	23.57	24.28	25.01	25.77	26.89
AEO2004					
Reference	23.30	24.17	25.07	26.02	27.00
Low price	16.98	16.98	16.98	16.98	16.98
GII	21.77	21.95	24.03	25.68	27.06
IEA	21.75	21.75	23.82	25.89	27.96
PEL	20.96	21.27	18.41	15.60	NA

PIRA	23.80	23.90	26.70	N/A	NA
NRCan	22.57	22.57	22.57	22.57	NA
DB	18.13	18.03	18.41	18.16	18.26
EEA	20.99	20.33	19.84	19.36	NA
NPC	18.00	18.00	18.00	18.00	18.00
SEER	21.08	19.86	20.88	22.49	24.53
CGES	23.82	21.27	18.41	15.60	NA

Comparisons with other oil price forecasts—including GII, the International Energy Agency (IEA), Petroleum Economics, Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), Natural Resources Canada (NRCan), Deutsche Bank A.G. (DB), Energy and Environmental Analysis, Inc. (EEA), National Petroleum Council (NPC), Strategic Energy & Economic Research, Inc. (SEER), and Centre for Global Energy Studies (CGES)—are shown in Table 7 (GII, Spring-Summer 2003; IEA, September 2002; PEL, April 2003; PIRA, October 2003; NRCan, 1997, reaffirmed in September 2002; DB, September 2003; EEA, October 2003; NPC, October 2003; SEER, November 2003; CGES, January 2003). The world oil price measure varies by forecast. In some it is the spot price for West Texas Intermediate (WTI), Brent, or a basket of crude oils. AEO2004 uses the composite U.S. refiners' acquisition cost of crude oil, including transportation and fees. There is no simple way to put the forecasts for oil prices (Table 7) on a common basis. With the exception of PEL and CGES, which fall below the AEO2004 low world oil price case in 2020, the range between the AEO2004 low and high world oil price cases spans the range of published forecasts.

Our two cases can be described as follows:

- The reference case represents the July 2004 judgment regarding the expected behaviour of OPEC producers in the mid-term, adjusting production to keep world oil prices in the $22 to $28 per barrel range.

- The low world oil/gas price case represents a future market in which all oil/gas production becomes more competitive and plentiful. It is considered that a low price scenario for the Balkans region corresponds to the possible introduction of Caspian Sea gas into the region through Turkey that would create competition against Russian Gazprom dominance. In recent years Turkey has moved to pre-empt expected increases in international and domestic natural gas demand by fostering international pipeline infrastructure, which may eventually connect producers in the Middle East and Northern Africa to Europe's natural gas grid. In February 2003, as part of an effort to integrate hydrocarbon transport networks in the region, Greece and Turkey signed an agreement to construct a 176-mile pipeline, to begin operation in 2005 with an initial capacity of 17.6 billion cubic feet. There is potential that Western Europe is then supplied through this pipeline via a number of the Balkan Countries included in this report. This potential Gas supply route is investigated further in a preliminary WB study [30].

Figure 7: A Map Showing Current and some proposed gas pipelines in South East Europe

All jurisdictions included in the study region are supplied with Russian gas except Albania, Kosovo and Montenegro who have no pipeline supplies of natural gas. These two distinct groups are discussed in turn:

Countries with existing gas pipeline supplies

- Bosnia & Herzegovina: Consumption is low and gas comes exclusively from a pipeline feeding Russian gas. The Bosnian pipeline is branched from the Serbian gas supply system so a gas price supplied by the Serbian utility, EPS is used as an indicative guide for the price of gas in Bosnia & Herzegovina, in the absence of more definitive data.

- Bulgaria: There are virtually no indigenous supplies of gas. Most of the natural gas imports are supplied from Russia, via Ukraine and Romania. Demand is expected to increase significantly by 2010 to over 8bcm [12] with additional demand expected from 2015-2020. Prices for gas were obtained from NEK and a Bulgarian gas company. The values were consistent and so an average value is taken.

- Croatia: The indigenous reserves of natural gas are declining, and the capacity of the Russian pipeline is restricted to 1.1 billion cubic meters. The favoured route for additional imports is understood to be an offshore pipeline originating from Italy. The Croatian Masterplan [26] gives a forecast demand for gas (see table below). HEP provided a gas price.

Table 8: Croatia natural gas supply demand balance

(10^3 m^3)	2000*	2005	2010	2015	2020	2025
Own production	1 577000	1 556 000	963 000	301 000	132 000	57 000
Current gas fields	1413 000	1 116 000	662 000	120 000	82 000	57 000
North Adriatic sea	164 000	440 000	301 000	181 000	50 000	0
Import	1 100000	2 300 000	2 900000	3 300 000	3 300 000	3 300 000
Russia	1 100 000	1 100 000	1 100 000	1 100 000	1 100 000	1 100 000
Italy	0	1 200 000	1 800 000	2 200 000	2 200 000	2 200 000
Own production+import	2 677 000	3 856 000	3 863 000	3 601 000	3 432 000	3 357 000
Forecast demand (less operational use)	2 554 600	2 938 304	3 648 294	3 830 737	4 301 266	4 895 633
Difference	122 400	917 696	214 706	-229 737	-869 266	-1 538 633

- FYR Macedonia: There is gas provided through the Russian pipeline via Bulgaria with a capacity of 1.2 bcm. This capacity would source the annual requirements of a planned 200MW CCGT. ECM supplied a gas price.

- Romania: The jurisdiction has the highest use of gas in SEE and is the only place where domestic gas production plays more than a marginal role, although its output is steadily decreasing. Imported gas is from Russia via Ukraine and the pipeline has a maximum capacity of 8bcm per annum. This capacity is likely to be reached by 2007. There are plans to increase the capacity of the pipeline to 14 bcm per annum. The Romanian National Regulatory Authority in the Natural Gas Sector (ARGN) supplied a gas price.

- Serbia (excluding UNMIK): There is some indigenous gas production and facilities for imported gas from Russia via Hungary. The Serbian Utility, EPS supplied a gas price.

All gas prices received from the utilities were assumed as the ‘likely’ gas prices for 2005 and adjusted to give January 2005 values. A ‘low’ gas price was calculated based on the ratio of the ‘low’ 2005 gas price to the ‘reference’ oil price given in the 2004 American Energy Outlook [34].

Low : Reference 2005 Oil Price Ratio	(16.98/23.30) = 0.73

The 2010, 2015, 2020 ‘low’ and ‘likely’ gas forecast prices were made using the projected annual changes shown in the “low and likely” oil forecasts presented in Table 7.

Bosnia & Herzegovina, Bulgaria, Macedonia, Romania and Serbia are all supplied with gas via the same main Russian pipeline via Ukraine. The trend in price for each of these countries is in line with the increased transportation costs as the pipeline travels first through Romania before splitting in two, one pipeline feeding Bulgaria and then onwards to Macedonia and the other to Serbia and then onwards to Bosnia & Herzegovina.

The supply of gas to Croatia is independent of transit through Romania. The country is fed with Russian gas via Slovakia, Austria and Slovenia.

Countries with no existing Gas Supply

- Albania: Domestic production is very limited and resources have declined significantly over recent years. There is a potential for gas imports into the country, which would support the construction of gas-fired generation. Gas price assumptions are based on the WB study into the cost of transporting natural gas into SEE [30], which considers gas entering the region through a new pipeline supplying Caspian Sea gas via Turkey and Greece.

- Montenegro: There is currently no gas sector within Montenegro. Although the WB study into the cost of transporting natural gas into SEE [30] does not directly consider Montenegro, there appears no definitive reason why the route through Greece could not have a gas branch directed towards Montenegro. On this assumption, gas prices given for Montenegro are assumed to be the same as Albania. The WB study [30] takes three scenarios for gas prices at the Greece/Turkey border, corresponding to low, medium and high oil price scenarios. Added to these costs were transport costs for the construction of the pipeline considering required pipeline size, the need for large compressors and data on the cost per length of pipeline in flat and steep terrain. Current large volume gas transport tariffs in Greece were used as estimates of transport costs across Greece. The costs in the WB study [30] represent 2002 gas prices so the figures were adjusted based on historical world oil price figures and inflation to represent 2005 prices. The timescale for the planning and construction of the pipeline would be such that gas would not be available in Albania and Montenegro until 2010.

- UNMIK: There is currently no gas sector within UNMIK. Existing gas pipelines would need to be extended by around 100km to bring natural gas to the jurisdiction. The ESTAP report [6] concluded that the cost of gas would be most economic if delivered from Russia through Hungary, Serbia and Montenegro or Romania, Bulgaria and FYR Macedonia. Gas was priced at the Ukrainian border and linked to oil prices, with additional transportation costs dependent on load factor. The timescale for the planning and construction of the pipeline would be such that gas would not be available in Kosovo until 2010. The likely price of gas in the region was supplied by KEK based on the findings from the ESTAP report [6] and future forecasted prices for 2010, 2015 and 2020 were based on the 2004 American Energy Outlook [34].

Consideration of relative prices of gas from alternative sources

When comparing the fuel prices calculated (see fuel price tables below) for the two gas supply scenarios into the region it suggests that Caspian gas (see Albania and Montenegro forecast gas prices) would not come into the region at a price lower than Russian gas (see Kosovo forecast gas prices) for the foreseeable future. For this reason, we do not anticipate major changes to the levels of gas prices.

Gas prices are given below in units of €/GJ and €/tcm (€/thousand cubic metres)

Table 9: Assumed natural gas costs – low case, €/GJ

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	2010	2015	2020
Gas (Low)								
Albania	-	-	-	-	-	2.97	2.97	2.97
Bosnia & Herzegovina	-	-	-	-	2.75	2.75	2.75	2.75
Bulgaria	-	-	-	-	2.45	2.45	2.45	2.45
Croatia	-	-	-	-	2.11	2.11	2.11	2.11
Unmik	-	-	-	-	-	2.83	2.83	2.83
FYR Macedonia	-	-	-	-	2.80	2.80	2.80	2.80
Montenegro	-	-	-	-	-	2.97	2.97	2.97
Romania	-	-	-	-	2.18	2.18	2.18	2.18
Serbia (excluding Unmik)	-	-	-	-	2.75	2.75	2.75	2.75

Table 10: Assumed natural gas costs – likely case, €/GJ

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	2010	2015	2020
Gas (Likely)								
Albania	-	-	-	-	-	4.92	4.92	4.92
Bosnia & Herzegovina	-	-	-	-	3.77	3.91	4.06	4.21
Bulgaria	-	-	-	-	3.36	3.48	3.61	3.75
Croatia	-	-	-	-	2.90	3.00	3.12	3.23
Unmik	-	-	-	-	-	4.11	4.26	4.42
FYR Macedonia	-	-	-	-	3.85	3.99	4.14	4.29
Montenegro	-	-	-	-	-	4.92	4.92	4.92
Romania	-	-	-	-	2.99	3.10	3.22	3.34
Serbia (excluding Unmik)	-	-	-	-	3.77	3.91	4.06	4.21

Table 11: Assumed natural gas costs – low case, €/tcm

	Fuel Costs - €/tcm (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	2010	2015	2020
Gas (Low)								
Albania	-	-	-	-	-	108	108	108
Bosnia & Herzegovina	-	-	-	-	99.8	99.8	99.8	99.8
Bulgaria	-	-	-	-	88.9	88.9	88.9	88.9
Croatia	-	-	-	-	76.6	76.6	76.6	76.6
Unmik	-	-	-	-	-	103	103	103
FYR Macedonia	-	-	-	-	102	102	102	102
Montenegro	-	-	-	-	-	108	108	108
Romania	-	-	-	-	79.1	79.1	79.1	79.1
Serbia (excluding Unmik)	-	-	-	-	99.8	99.8	99.8	99.8

Table 12: Assumed natural gas costs - likely case, €/tcm

	Fuel Costs - €/tcm (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	2010	2015	2020
Gas (Likely)								
Albania	-	-	-	-	-	179	179	179
Bosnia & Herzegovina	-	-	-	-	137	142	147	153
Bulgaria	-	-	-	-	122	126	131	136
Croatia	-	-	-	-	105	109	113	117
Unmik	-	-	-	-	-	149	155	160
FYR Macedonia	-	-	-	-	140	145	150	156
Montenegro	-	-	-	-	-	179	179	179
Romania	-	-	-	-	109	113	117	121
Serbia (excluding Unmik)	-	-	-	-	137	142	147	153

3.5.4 Oil

There are no large oil reserves in the Balkans. Oil-fired generation requires imported fuel. Cost assumptions include an allowance for transport and storage of 0.80 €/GJ. World Oil prices were taken from the American Energy Outlook 2004 forecast [34] (see Table 7) with 2002 US dollar prices converted to January 2005 figures assuming an annual rate of inflation of 3%. Ratios of heavy fuel oil price (sulphur content < 1%) and gas oil (distillate) to crude oil price were taken from the Bulgarian EER report [9]. The report took ratios for the period 1990-2000 and calculated averages for this time period. A ratio of diesel price to gas oil price was taken from the Albanian Decon report [35]. The table below shows the ratios used:

Table 13: Ratio of oil prices to crude oil

	Ratio to crude oil price
Crude Oil	1.00
HFO	0.81
Gasoil (distilliate)	1.24
Diesel	1.32

Data on heavy fuel oil prices was received from Croatia and Macedonia. These were used to determine HFO oil price estimates for 2005. Future forecasted prices for 2010, 2015 and 2020 were based on the 2004 American Energy Outlook [34].

The 2005 reference price forecast from the American Energy Outlook 2004 forecast [34] with 2002 US dollar prices converted to January 2005 figures assuming an annual rate of inflation of 3% works out at $26 per barrel. This is significantly less than the current price of oil which, at the time of writing (December 04), is around the $50 per barrel mark. The current "high" price is a temporary price excursion as a result of the troubles in Iraq, among other factors. The above price of $26 per barrel is in line with OPEC price predictions that future oil prices will drop back to within the 22-28 US dollar range once the global supply situation stabilises.

Due to the high cost of oil compared to gas and the greater emissions released from oil fired power stations it is unlikely that oil would be considered as a main source of fuel for power generation in the region. The main reason for the future for oil in the region is that it would serve as a temporary fuel source in potential new build CCGT power stations in Albania, Kosovo and Montenegro whilst gas supply pipelines are constructed in the region.

Table 14: Assumed distillate oil costs

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Oil – Gasoil (Distillate)								
Albania	-	-	-	-	5.47	5.65	5.83	6.02
Bosnia & Herzegovina	-	-	-	-	5.47	5.65	5.83	6.02
Bulgaria	-	-	-	-	5.47	5.65	5.83	6.02
Croatia	-	-	-	-	5.47	5.65	5.83	6.02
Unmik	-	-	-	-	5.47	5.65	5.83	6.02
FYR Macedonia	-	-	-	-	5.47	5.65	5.83	6.02
Montenegro	-	-	-	-	5.47	5.65	5.83	6.02
Romania	-	-	-	-	5.47	5.65	5.83	6.02
Serbia (excluding Unmik)	-	-	-	-	5.47	5.65	5.83	6.02

Table 15: Assumed HFO costs

	Fuel Costs - €/GJ (constant 2005 price level) Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Oil - Heavy Fuel Oil > 1%								
Albania	-	-	-	-	3.85	3.97	4.08	4.21
Bosnia & Herzegovina	-	-	-	-	3.85	3.97	4.08	4.21
Bulgaria	-	-	-	-	3.85	3.97	4.08	4.21
Croatia	-	-	-	-	3.79	3.97	4.08	4.21
Unmik	-	-	-	-	3.85	3.97	4.08	4.21
FYR Macedonia	-	-	-	-	4.61	3.97	4.08	4.21
Montenegro	-	-	-	-	3.85	3.97	4.08	4.21
Romania	-	-	-	-	3.85	3.97	4.08	4.21
Serbia (excluding Unmik)	-	-	-	-	3.85	3.97	4.08	4.21

Table 16: Assumed diesel costs

	Fuel Costs - €/GJ (constant 2005 price level) Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Diesel								
Albania	-	-	-	-	5.77	5.96	6.15	6.36
Bosnia & Herzegovina	-	-	-	-	5.77	5.96	6.15	6.36
Bulgaria	-	-	-	-	5.77	5.96	6.15	6.36
Croatia	-	-	-	-	5.77	5.96	6.15	6.36
Unmik	-	-	-	-	5.77	5.96	6.15	6.36
FYR Macedonia	-	-	-	-	5.77	5.96	6.15	6.36
Montenegro	-	-	-	-	5.77	5.96	6.15	6.36
Romania	-	-	-	-	5.77	5.96	6.15	6.36
Serbia (excluding Unmik)	-	-	-	-	5.77	5.96	6.15	6.36

3.5.5 Nuclear fuel

Our assumptions on the cost of nuclear fuel are based on the EER report [9]. At the time, NEK's estimate was €5.47/MWh ($6.75/MWh), which represented the higher end of international experience of nuclear plants. The DECADES programme of the IAEA has documented the costs of most nuclear plant worldwide and reports fuel costs in the range €4.74/MWh to €9.85/MWh ($5.85/MWh to $12.16/MWh). Plant similar to those in Bulgaria had fuel costs of €7.29/MWh ($9/MWh). These prices have been uprated in line with inflation. Future forecast prices show that the cost of nuclear fuel will remain fairly stable up to 2020.

3.6 Fuel Costs – Utility Data

The following prices have been provided by utilities and come from a number of sources:

- Completion or partial completion of the SEETEC spreadsheets;
- Completion of the Technical Team information requests; and
- Other written information supplied to the Technical Team.

Much of this information is used in the above section, but has been set down here to provide clarity of sources.

3.6.1 Albania

No utility specific prices have been provided although the Albanian Decon report [34] was suggested as a suitable source for information.

3.6.2 Bosnia & Herzegovina

Provided by utilities by completion of Technical Team information requests and additional faxed information from the utilities.

Table 17: Bosnia & Herzegovina fuel costs provided by utilities

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite/Br Coal (EPBiH), Tuzla B1, Kamangrad, Tuzla VI : Unit 7, Kakanj VI Unit 8	2.033				-	-	-	-
Lignite/Br Coal (EPRS):								
Banja Luka	1.36				-	-	-	-
Ugljevik II	2.52				-	-	-	-
Gacko II	2.51				-	-	-	-

3.6.3 Bulgaria

The following values are taken from the SEETEC spreadsheet as filled in by NEK.

Table 18: Bulgaria fuel costs provided by NEK

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (MEast3)	1.041				-	-	-	-
Lignite (MEast2, 1-4)	0.824				-	-	-	-
Lignite (MEast2, 5-8)	0.998				-	-	-	-
Lignite (Maritza 3)	1.283				-	-	-	-
Brown Coal (Bdol)	2.045				-	-	-	-
Hard Coal (Varna)	-	-	-	-	1.469			

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Hard Coal (Ruse)	-	-	-	-	1.571			
Gas	-	-	-	-	3.015			

3.6.4 Croatia

The following values are taken from the SEETEC spreadsheet as filled in by HEP.

Table 19: Coatia fuel costs provided by HEP

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Hard Coal	-	-	-	-	1.37			
Gas	-	-	-	-	2.84			
HFO	-	-	-	-	3.79			
Uranium Oxide					0.337			

3.6.5 UNMIK

No utility specific prices have been provided although the ESTAP report [6] was suggested as a suitable source for information.

3.6.6 FYR Macedonia

The following values are taken from the SEETEC spreadsheet as filled in by ESM and material provided by them.

Table 20: Macedonia fuel costs provided by ESM

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (existing plant)	1.09		-	-	-	-	-	-
Lignite (Bitola Rehab)	-	-	1.48		-	-	-	-
Lignite (Osmomej Rehab)	-	-	1.48		-	-	-	-
Lignite (Negotino Rehab)	-	-	1.25		-	-	-	-
Lignite (Bitola 4)	-	-	-	-	-	-	1.69	
Gas	-	-	-	-	-	3.77		
HFO	-	-	-	-	4.61			

3.6.7 Montenegro

These values have been provided as additional material by EPCG.

Table 21: Montenegro fuel costs provided by EPCG

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020

Lignite (Pljevlja 1)	2.33	-	-	-	-
Lignite (Pljevlja 2)	2.48	-	-	-	-

3.6.8 Romania

No pricing information has been provided by TEL.

3.6.9 Serbia

The following values are taken from the SEETEC spreadsheet as filled in by EPS.

Table 22: Serbia fuel costs provided by EPS

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (existing & rehab plant except NT A6, Morava, Kostolac)	1.29				-	-	-	-
Lignite (NT A6, Kostolac)	1.39				-	-	-	-
Lignite (Morava)	4.06				-	-	-	-
Lignite (future Kolubara B)	1.18				-	-	-	-
Lignite (future NT B3, Kolubara A6)	1.29				-	-	-	-
Lignite (Kostolac B3)	1.39				-	-	-	-
Gas	-	-	-	-	3.70			

3.7 Fuel Costs – Reconciliation, Forecast Study Prices

Using both generic data and fuel prices supplied by utilities the following fuel prices are used in the study work.

Albania

Table 23: GIS assumed fuel costs for Albania

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Imported Coal	-	-	-	-	1.68	1.68	1.68	1.68
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	-	2.97	2.97	2.97
Gas (likely scenario)	-	-	-	-	-	4.92	4.92	4.92
Gas (high scenario)	-	-	-	-	-	6.50	6.50	6.50

Bosnia & Herzegovina

Table 24: GIS assumed fuel costs for BiH

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite/Brown Coal (EPBiH) Tuzla B1, Kamangrad, Tuzla VI – Unit 7, Kakanj VI Unit 8	2.03	2.03	2.03	2.03	-	-	-	-
Lignite (Banja Luka)	1.36	1.36	1.36	1.36	-	-	-	-
Brown Coal (Ugljevik II)	2.52	2.52	2.52	2.52	-	-	-	-
Lignite (Gacko II)	2.51	2.51	2.51	2.51	-	-	-	-
Lignite (Generic)	1.71	1.71	1.71	1.71	-	-	-	-
Hard Coal	2.14	2.14	2.14	2.14	1.68	1.68	1.68	1.68
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	2.75	2.75	2.75	2.75
Gas (likely scenario)	-	-	-	-	3.77	3.91	4.06	4.21
Gas (high scenario)	-	-	-	-	5.04	5.39	5.54	5.61

Bulgaria

Table 25: GIS assumed fuel costs for Bulgaria

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (MEast3)	1.04	1.04	1.04	1.04	-	-	-	-
Lignite (MEast2,1-4)	0.82	0.82	0.82	0.82	-	-	-	-
Lignite (MEast2,5-8)	1.00	1.00	1.00	1.00	-	-	-	-
Lignite (Maritza 3)	1.28	1.28	1.28	1.28	-	-	-	-
Lignite (generic)	0.88	0.88	0.88	0.88	-	-	-	-
Brown Coal (Bdol)	2.04	2.04	2.04	2.04	-	-	-	-
Hard Coal (Varna)	-	-	-	-	1.47	1.47	1.47	1.47
Hard Coal (Ruse)	-	-	-	-	1.57	1.57	1.57	1.57
Hard Coal (generic)	-	-	-	-	1.68	1.68	1.68	1.68
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	2.45	2.45	2.45	2.45
Gas (likely scenario)	-	-	-	-	3.36	3.48	3.61	3.75
Gas (high scenario)	-	-	-	-	4.49	4.79	4.93	4.99

Croatia

Table 26: GIS assumed fuel costs for Croatia

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Hard Coal (existing plant)	-	-	-	-	1.37	1.37	1.37	1.37
Hard Coal (generic)	-	-	-	-	1.68	1.68	1.68	1.68
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.79	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	2.11	2.11	2.11	2.11
Gas (likely scenario)	-	-	-	-	2.90	3.00	3.12	3.23
Gas (high scenario)	-	-	-	-	3.87	4.14	4.26	4.31

UNMIK

Table 27: GIS assumed fuel costs for UNMIK

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (existing plant)	0.62	0.62	-	-	-	-	-	-
Lignite (generic)	-	0.62	0.62	0.62	-	-	-	-
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	-	2.83	2.83	2.83
Gas (likely scenario)	-	-	-	-	-	4.11	4.26	4.42
Gas (high scenario)	-	-	-	-	-	4.47	4.60	4.65

FYR Macedonia

Table 28: GIS assumed fuel costs for Macedonia

	Fuel Costs - €/GJ							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (existing plant)	1.09	1.09	-	-	-	-	-	-
Lignite (Bitola Rehab)	-	-	1.48	1.48	-	-	-	-
Lignite (Osmomej Rehab)	-	-	1.48	1.48	-	-	-	-
Lignite (Negotino Rehab)	-	-	1.25	1.25	-	-	-	-
Lignite (generic)	1.34	1.34	-	-	-	-	-	-
Lignite (Bitola 4 & geneirc)	-	-	-	-	-	-	1.66	1.66
Hard Coal	-	-	-	-	1.68	1.68	1.68	1.68
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	4.61	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	2.80	2.80	2.80	2.80
Gas (likely scenario)	-	-	-	-	3.85	3.99	4.14	4.29
Gas (high scenario)	-	-	-	-	5.14	5.49	5.65	5.72

Montenegro

Table 29: GIS assumed fuel costs for Montenegro

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (Pljevlja 1)	2.33	2.33	2.33	2.33	-	-	-	-
Lignite (Pljevlja 2)	2.48	2.48	2.48	2.48	-	-	-	-
Lignite (generic)	2.44	2.44	2.44	2.44	-	-	-	-
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	-	2.97	2.97	2.97
Gas (likely scenario)	-	-	-	-	-	4.92	4.92	4.92
Gas (high scenario)	-	-	-	-	-	6.50	6.50	6.50

Romania

Table 30: GIS assumed fuel costs for Romania

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite	1.52	1.52	1.52	1.52	-	-	-	-
Hard Coal	2.37	2.37	2.37	2.37	1.68	1.68	1.68	1.68
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	2.18	2.18	2.18	2.18
Gas (likely scenario)	-	-	-	-	2.99	3.10	3.22	3.34
Gas (high scenario)	-	-	-	-	4.00	4.27	4.39	4.44

Serbia (excluding UNMIK)

Table 31: GIS assumed fuel costs for Serbia

	Fuel Costs - €/GJ (constant 2005 price level)							
	Local				Imported			
	2005	2010	2015	2020	2005	1010	2015	2020
Lignite (existing & rehab plant except NT A6, Morava, Kostolac)	1.29	1.29	1.29	1.29	-	-	-	-
Lignite (NT A6, Kostolac)	1.39	1.39	1.39	1.39	-	-	-	-
Lignite (Morava)	4.06	4.06	4.06	4.06	-	-	-	-
Lignite (future Kolubara B)	1.18	1.18	1.18	1.18	-	-	-	-
Lignite (future NT B3, Kolubara A6)	1.29	1.29	1.29	1.29	-	-	-	-
Lignite (Kostolac B3)	1.39	1.39	1.39	1.39	-	-	-	-
Lignite (generic)	1.34	1.34	1.34	1.34	-	-	-	-
Oil – Gasoil (distillate)	-	-	-	-	5.47	5.65	5.83	6.02
Oil – Heavy Fuel Oil < 1%	-	-	-	-	3.85	3.97	4.08	4.21
Diesel	-	-	-	-	5.77	5.96	6.15	6.36
Gas (low scenario)	-	-	-	-	2.75	2.75	2.75	2.75
Gas (likely scenario)	-	-	-	-	3.77	3.91	4.06	4.21
Gas (high scenario)	-	-	-	-	5.04	5.39	5.54	5.61

3.8 *Base case assumptions*

Running the WASP and GTMax models requires the verification of a number of technical, operational and economic data concerning each existing and candidate power plant. It comprises of the following:

- Thermal Power Plant
  - Technical data for each unit in each plant comprising the name, type, installed capacity, fuel type, economic lifetime, energy content of fuel.
  - Operational data for each unit in each plant comprising the maximum and minimum operating capacity (annual or weekly values), heat rate at minimum and maximum operating capacity, spinning reserve requirements (annual or weekly values), internal energy consumption factor, maintenance requirements, forced outage rate (annual or weekly values) and SO_2 and NO_x emission factors.
  - Economic data for each unit in each plant comprising the fuel cost, fixed and variable O&M costs.
- Hydro Power Plant
  - Technical data for plant comprising the name, type, installed capacity, economic lifetime, energy value of useful storage.
  - Operational data for each plant comprising the expected electricity generation and maximum available capacity as well as minimum (base) generation in each month and for three characteristic hydrological conditions (average, wet and dry) including probabilities of the hydro conditions, spinning reserve requirements (annual or weekly values), maintenance requirements, and forced outage rate.
  - Economic data for each plant comprising the fixed O&M costs.
- Pumped-Storage Power plant
  - Technical data for plant comprising the name, type, installed generating and pumping capacity, cycle efficiency and status.
  - Operational data for each plant comprising the maximum generating and pumping capacity in each month.
  - Economic data for each plant comprising the fixed O&M costs.

Details related to existing and specific candidate and rehabilitation options are described in Appendices 7 and 8.

3.8.1 Expansion planning and economic criteria

Within the data requirements for WASP, there are a number of general assumptions related to expansion planning and economic assumptions. We describe our base case assumptions and highlight the changes that are considered under the sensitivity runs and scenarios.

- Planning period is from 1 January 2005 to 31 December 2020.

- All costs are at January 2005 base price level and do not include any general inflation.

- The analysis is undertaken in Euros and an exchange rate of $1 to €0.8375.

- Fuel price forecasts are described in section 2.5.

- We assume a real discount rate of 10%, discounted to January 2005. In one sensitivity run, we consider the impact of a reduced discount rate of 7%.

- We use a range of reserve margins for the initial WASP selection of potential expansion plans from the set of all possible configurations composed of the existing and candidate plant. Within the DYNPRO module, our base assumption for Loss of Load Probability (LOLP) is one day per annum. This provides comparable reserve margins for the final expansion plans. A LOLP of one day per year is based on consideration of the range of values assumed in other studies within the region, the usual value used worldwide and recognition that the main results will be focused on the regional scenarios. We note that some utilities would currently have difficulties in achieving a LOLP of one day per annum due to deficiencies in the transmission and distribution systems and insufficient generation. Nevertheless, if all utilities are to participate in a regional market, it is important that common quality of supply standards are achieved and a target LOLP of one day per annum (cumulative) is in accordance with best international practice.

- The amount of the undelivered energy cost is a value difficult to determine in exact terms. There is no generally accepted method for determining such costs. They differ from one country to another and are dependent on many factors such as demand structure, quantity of undelivered electricity and the duration of supply interruption. A number of studies and plans within the region have assumed a value of 0.5$/kWh (which equates to 0.4€/kWh) and we have adopted this value as our assumption.

3.8.2 Nuclear plant

In relation to nuclear plant, we make the following assumptions:

- Bulgaria: Kozloduy units 1 and 2 retired already; units 3 and 4 retire in December 2006; units 5 and 6 available through 2020;

- Bulgaria: Belene unit 1 of 1,000 MW unit is included as a candidate plant to start operation at the earliest 1 January 2008;

- Romania: Cernavoda unit 1 available through 2020; units 2-4 are included as candidate plants; and

- Croatia: Krsko unit 1 available through 2020, with a 50/50 split of output with Slovenia.

3.8.3 Thermal plant

Details on actual refurbishment and/or retirement plans from utilities are shown in Appendix 8. Where no specific plans stated have been provided to us by the utilities, assumptions are as follows:

- Units will be assigned economic operating lives of:
  - Coal/lignite 40 years
  - Oil/gas steam 30 years
  - Combined cycle 25 years
  - Open cycle GT 20 years
- For computation of WASP residual values in 2020, new units will be assigned the following economic lives:
  - Coal/lignite 30 years
  - Oil/gas steam 25 years
  - Combined cycle 20 years
  - Open cycle GT 15 years
  - Rehabilitated plant 15 years
- For rehabilitation and environmental controls, the following assumptions were made:
  - For Romania and Bulgaria, plans given by the utilities and ministries are followed for both rehabilitation and environmental controls that include full compliance (particulate, NOx and SOx controls) with EC regulations;
  - For the other countries, plans given by the utilities and ministries are followed where available. However, because most of these countries do not have rehabilitation and environmental control plans, we have assumed that essential rehabilitation for reliability improvements and particulate and NOx controls will be implemented approximately 25 years after commissioning (or later for units that are more than 25 years old and have not implemented such plans at the beginning of the study period). There will be no expensive SOx controls installed during the study period; and
  - Under Scenario C, a sensitivity case is performed to analyse the impact of full environmental compliance in all jurisdictions.

- The following plant with advance funding proposals are assumed to proceed, specifically:
  - 100MW combined cycle, Albania; and
  - 600MW Maritsa East 1 new build (2 x 300MW), Bulgaria.

3.8.4 CHP Plants

- Unless specified by the utilities, CHP plants are assumed to continue operation through to 2020. Operation of current plant are mostly dependent on heat supply.
- Due to the relatively small size of each unit and the lack of specific plans for potential upgrade or rehabilitation, CHP plant are assumed to continue current practices of operation.

3.8.5 Hydro and renewable plant

- All existing hydro plant will continue operation through 2020, under current operating policies. Unless specific rehabilitation and upgrade plans are provided by the utilities, existing characteristics of hydro plant remain the same for the entire study period.
- New hydro candidates from identified sites with feasibility studies as specified by the utilities are included.
- Other renewables are considered to have a small impact on future generation and are relatively expensive. They are excluded from this study.

3.8.6 Imports and exports

- Currently, power imports and exports within the SEE region and with surrounding countries are based on short-term transactions and not on long-term agreements, except for a few cases of sharing power plant between jurisdictions. Historical data show great variations from year to year.
- The impact of rejoining of UCTE 1 and 2 increased the potential for major power transactions but there is no indication at this time of the timing and magnitude of these transactions.
- It is beyond the scope of this study to evaluate the market attractiveness of buying or selling outside the SEE region. As a result, no outside imports into the SEE region or exports from the SEE region to outside countries is considered in the Base Case assumptions of Scenarios A, B and C.
- Under Scenario C, a sensitivity run is made, based on a “what-if?” scenario. This sensitivity run assumes a net import of 1,500MW into the region, starting in 2010 until 2020. It is impossible to predict at this time the levels of imports and exports with each country outside the SEE region, but we assume a net import of 750MW from Ukraine, 750MW from the European UCTE network and

500MW from Turkey, and a net export of 500MW to Greece. All transactions are assumed to be baseload, 24 hours per day.

- Within the SEE region, under Scenario A (individual jurisdictions), no imports or exports are assumed between jurisdictions, except 1) for base-load and peaking imports to Albania until 2010, 2) for importing peaking power, 3) for replacement capacity and energy when existing units will be under rehabilitation for a period of one or two years, and 4) for sharing capacity reserve requirements to meet reserve margins and LOLP criteria.

- Under Scenario B, there are no limits on imports and exports within the SEE region.

- Under Scenario C, limits on imports and exports are based on the physical capacity constraints of the existing and proposed transmission interconnection networks between jurisdictions, and analysed with the GTMax model. The base case assumptions reflect the transmission interconnection network proposed by the SECI Committee.

3.9 Scenarios A, B, and C Results

3.9.1 Introduction

The analysis of alternative development options includes the preparation of three alternative generation expansion scenarios. The first scenario (Scenario A) consists of individual least cost plans for capacity expansion plans in each of the nine power systems, without the benefits of regional cooperation. The other two scenarios (Scenarios B and C) include the benefits of regional cooperation and integration at various levels.

The key results of these three scenarios are presented in the following pages. More details are given in Appendix 12.

3.9.2 Scenario A Results

Scenario A is developed as a reference to compute the total net present value (NPV) of construction and operation costs within each jurisdiction over the study period of 2005-2020. The NPV sum for the nine individual jurisdictions is then compared to the NPVs of Scenarios B and C to evaluate the benefits of regional electric power planning and integration.

The WASP model is used to develop an expansion plan for each jurisdiction. Since Scenario A is only used for reference purposes, the expansion plans shown in the following pages are just an indication of least-cost plans. The plans are based on the medium load forecast and are developed from data provided by the utilities and other government agencies as presented in previous sections of this report as well as in Appendix 7: Country Data Profiles, and Appendix 8: Specific Candidate Plants.

The plans are based on the rehabilitation programs given by the utilities. No adjustments are made to the planned timing of rehabilitation. Rehabilitation costs were obtained from the utilities and reviewed and updated by the SEEC Environmental Team. Details of these costs are shown in Appendix 9 and in SEEC's report entitled "GIS – Implications for Investments in Environmental Protection". Rehabilitation includes technical rehabilitation (life extension) and full environmental compliance (particulate, NOx and SOx controls) with EC regulations (Directive 2001/80/EC) for Romania and Bulgaria. For the other jurisdictions, rehabilitation includes technical rehabilitation and partial environmental compliance (particulate and NOx) for plants planned for rehabilitation.

Details of Scenario A results for each jurisdiction are presented in Appendix 12. For each jurisdiction, the WASP model computes a net present value (NPV) for all investments and O&M costs, covering the period 2005-2020. Table 32 summarises the results. The total NPV is estimated at €37.1 billion.

Table 32: Net Present Value of Investment and Operating Costs (€ million)

Jurisdiction	Investment Costs in Life Extension and Rehabilitation	Investment Costs in New Capacity and Total Operating Costs	Total
Albania	33	1,920	1,952
Bosnia & Herzegovina	354	2,074	2,427
Bulgaria	1,791	6,746	8,537
Croatia	0	4,241	4,241
Macedonia	140	1,740	1,880
Montenegro	44	903	947
Romania	1,086	9,391	10,476
Serbia	673	4,948	5,621
UNMIK	0	1,533	1,533
Total	**4,121**	**29,971**	**37,093**

Table 33 summarises the yearly expansion plans for the units planned for life extension and rehabilitation and for new capacity additions. The total addition is 11,574 MW for life extension and rehabilitation and 15,488 MW for new capacity additions.

Table 33: Scenario A Plants Planned for Rehabilitation and Additions

Year	Life Extension & Rehabilitation	New Capacity
2005		
2006	Maritsa East 3 (189 MW)x2 Maritsa East 2 (148 MW) Ruse 3 (100 MW) Novi Sad1 (100 MW) Zrenjanin (100 MW)	Bucuresti Sud (100MW)
2007	Fierza (58 MW) Balsh (11MW) Tuzla 5 (182 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Turceni 5 (272 MW) Deva 1 (167 MW) Nikola Tesla A4 (280 MW) Kostolac A1 (90 MW) Novi Sad21 (108 MW)	Bucuresti Sud (100MW) Cerna Voda 2 (664 MW)
2008	Tuzla 6 (198 MW) Kakanj 6 (100 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Rovinari 3 (278 MW) Galati 3 (92 MW) Deva 2 (167 MW) Nikola Tesla A6 (280 MW)	Bucuresti Vest (100MW) CCHP (86 MW) Combined cycle (288 MW)
2009	Gacko (276 MW) Maritsa East 2 (148 MW) Maritsa East 2 (185 MW) Ruse 4 (100 MW) Turceni 6 (272 MW) Isalnita 7 (266 MW) Paroseni 4 (120 MW)	Vlora 1 (132 MW) Maritsa East 1 (275 MW)x2 Combined cycle (288 MW)x2 Combined cycle (288 MW) Combined cycle (288 MW)
2010	Bobov Dol 1 (198 MW) Varna 1 (200 MW) Ruse 1 (25 MW) Turceni 3 (272 MW) Galati 4 (50 MW) Nikola Tesla A1 (191 MW) Deva 4 (167 MW)	Vlora 2 (132 MW) Combined cycle (288 MW) Combined cycle (144 MW) CCHP (86 MW) Combined cycle (144 MW) Bitola 4 (203 MW) CCHP (174 MW) Gas Turbine (63 MW) HPP Kostanica (552 MW) Bucuresti Vest (100MW) Kolubara B (320 MW) Kosovo (135 MW)x2
2011	Ugljevik (279 MW) Bobov Dol 2 (198 MW) Varna 2 (200 MW) Ruse 2 (25 MW) Pljevlja (191 MW) Negotino (197 MW) Rovinari 5 (278 MW) Nikola Tesla A2 (191 MW)	HPP Kalivaci (90MW) Simple cycle (96 MW) CCHP (86 MW)x2 Simple cycle (96 MW) Kolubara B (320 MW) Lignite Subcritical (270 MW)x3 Kosovo B3 (274 MW)
2012	Bobov Dol 3 (198 MW) Varna 3 (200 MW) Ruse 5 (25 MW) Nikola Tesla B1 (580 MW)	CCHP (86 MW) Coal Subcritical (270 MW) Combined cycle (288 MW)
2013	Varna 4 (200 MW)	HPP Bushati (47MW)

Year	Life Extension & Rehabilitation	New Capacity
	Ruse 6 (25 MW) Oslomej (109 MW) Galati 5 (92 MW)	CCHP (86 MW)x2 Combined cycle (288 MW) Combined cycle (288 MW)
2014	Varna 5 (200 MW) Galati 6 (92 MW) Nikola Tesla B2 (580 MW)	Combined cycle (144 MW) Gas Turbine (122 MW) Lukovo Polje (25 MW) CCHP (86 MW) Combined cycle (288 MW)
2015	Varna 6 (200 MW) Bitola 1 (207 MW)	Combined cycle (480 MW) CCHP (86 MW) Combined cycle (288 MW)
2016	Kostolac B1 (320 MW)	HPP Bratila (80MW) CCHP (86 MW) Combined cycle (288 MW) Banja Luka (122 MW) Gas Turbine (63 MW) HPP Matka 2 (35 MW) HPP Boskov Most (45 MW)
2017	Bitola 2 (207 MW)	Combined cycle (144 MW) Coal Subcritical (270 MW) Cerna Voda 3 (664 MW)
2018	Kostolac B1 (320 MW)	Tuzla 7 (340 MW) Combined cycle (288 MW) CCHP (86 MW) New Rovinari site (285 MW) Kosovo (135 MW)
2019		Vlora 3 (191 MW) Kakanj8 (212 MW) Gas Turbine (122 MW) HPP Gradec (55 MW) HPP Cebren (157 MW) HPP Spilje (73 MW) HPP Galiste (194 MW) CCHP (86 MW)x2 Lignite Subcritical (275 MW)
2020	Bitola 3 (207 MW)	Simple cycle (96 MW) Simple cycle (96 MW) Lignite Supercritical (450 MW)
Total	11,574 MW	15,488 MW

Table 34 summarises annual construction costs. Details for the units under life extension and rehabilitation (€5.86 billion) are presented in Table 35 and in Table 37 for new capacity (€ 12.1 billion).

Table 34: Non-Discounted Construction Costs for Scenario A

(€ million – 2005 Price Level)

Year	Life extension and Rehabilitation	New Capacity	Total
2005	491	580	1,071
2006	695	520	1,215
2007	784	1,235	2,019
2008	695	1,553	2,248
2009	820	1,259	2,079
2010	672	662	1,334
2011	499	446	945
2012	178	469	647
2013	415	690	1,105
2014	156	862	1,018
2015	178	993	1,171
2016	48	1,174	1,222
2017	130	994	1,124
2018	0	522	522
2019	99	164	263
2020	0	0	0
Total	**5,860**	**12,123**	**17,983**

Table 35: Non-discounted Annual Construction Costs for Life Extension and Rehabilitation (2005 Price Level)

Jurisdiction	TPP Unit Name	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Albania	TPP Fier Czech	10.3	10.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.5
	TPP Fier China	5.5	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
	Subtotal	***15.8***	***15.8***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***31.5***
B&H	Gacko	-	-	-	121.6	-	-	-	-	-	-	-	-	-	-	-	-	121.6
	Ugljevik	-	-	-	-	-	119.4	-	-	-	-	-	-	-	-	-	-	119.4
	Tuzla 5	41.1	41.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82.3
	Tuzla 6	-	43.1	43.1	-	-	-	-	-	-	-	-	-	-	-	-	-	86.3
	Kakanj 6	-	-	40.9	-	-	-	-	-	-	-	-	-	-	-	-	-	40.9
	Subtotal	***41.1***	***84.3***	***84.0***	***121.6***	***0.0***	***119.4***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***450.5***
Bulgaria	TPP Maritsa East 3 Unit 1	-	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 3 Unit 2	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 3 Unit 3	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 3 Unit 4	-	-	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 2 Unit 1	77.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 2	-	77.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 3	-	-	77.0	-	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 4	-	-	-	77.0	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 5	-	-	-	-	119.5	-	-	-	-	-	-	-	-	-	-	-	119.5
	TPP Maritsa East 2 Unit 6	-	-	-	119.5	-	-	-	-	-	-	-	-	-	-	-	-	119.5
	TPP Bobov Dol 1	-	-	-	-	110.5	-	-	-	-	-	-	-	-	-	-	-	110.5
	TPP Bobov Dol 2	-	-	-	-	-	110.5	-	-	-	-	-	-	-	-	-	-	110.5
	TPP Bobov Dol 3	-	-	-	-	-	-	110.5	-	-	-	-	-	-	-	-	-	110.5
	TPP Varna 1	-	-	-	-	108.2	-	-	-	-	-	-	-	-	-	-	-	108.2
	TPP Varna 2	-	-	-	-	-	111.8	-	-	-	-	-	-	-	-	-	-	111.8
	TPP Varna 3	-	-	-	-	-	-	111.8	-	-	-	-	-	-	-	-	-	111.8
	TPP Varna 4	-	-	-	-	-	-	-	109.3	-	-	-	-	-	-	-	-	109.3
	TPP Varna 5	-	-	-	-	-	-	-	-	108.2	-	-	-	-	-	-	-	108.2
	TPP Varna 6	-	-	-	-	-	-	-	-	-	108.2	-	-	-	-	-	-	108.2
	TPP Ruse 1	-	-	-	-	17.5	-	-	-	-	-	-	-	-	-	-	-	17.5
	TPP Ruse 2	-	-	-	-	-	17.5	-	-	-	-	-	-	-	-	-	-	17.5
	TPP Ruse 3	44.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44.0
	TPP Ruse 4	-	-	-	40.0	-	-	-	-	-	-	-	-	-	-	-	-	40.0
	TPP Ruse 5	-	-	-	-	-	-	18.0	-	-	-	-	-	-	-	-	-	18.0
	TPP Ruse 6	-	-	-	-	-	-	-	18.9	-	-	-	-	-	-	-	-	18.9
	Subtotal	***353.3***	***193.2***	***193.2***	***236.5***	***355.7***	***239.7***	***240.2***	***128.2***	***108.2***	***108.2***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***2,156.3***
Macedonia	Bitola 1	-	-	-	-	-	-	-	-	48.0	48.0	-	-	-	-	-	-	96.0

Table 37: Non-discounted Annual Construction Costs for New Capacity (2005 Price Level)

Jurisdiction	Year of Commission	Plant Name	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
Albania	2010	CCG3			6.3	85.9	81.7											173.9
	2010	CC15				30.2	65.9											96.1
	2010	CCHP			4.0	24.0	13.0											41.0
	2010	VLNN				18.5	40.5											59.0
	2011	BRAT			5.2	25.9	47.7	20.2										99.0
	2012	CCHP					4.0	24.0	13.0									41.0
	2013	BUSH					3.7	18.8	34.6	14.7								71.8
	2014	CC15								30.2	65.9							96.1
	2016	CCHP									4.0	24.0	13.0					41.0
	2016	KALI							3.8	15.8	35.6	36.9	11.9					104.0
	2017	CC15											30.2	65.9				96.1
	2019	VLO2												6.6	39.3	21.2		67.1
	2020	OC10														2.9	27.1	30.0
Subtotal			**0.0**	**0.0**	**15.5**	**184.5**	**256.5**	**63**	**51.4**	**60.7**	**105.5**	**60.9**	**55.1**	**72.5**	**39.3**	**24.1**	**27.1**	**1016.1**
B&H	2010	CC15				28.9	63.2											92.1
	2016	BLUK									9.7	58	31.3					99.0
	2018	TUZ7										22.3	111.8	205.7	87.3			427.1
	2019	KAK8											13.9	69.7	128.3	54.4		266.3
Subtotal			**0.0**	**0.0**	**0.0**	**28.9**	**63.2**	**0.0**	**0.0**	**0.0**	**9.7**	**80.3**	**157.0**	**275.4**	**215.6**	**54.4**	**0.0**	**884.5**
Bulgaria	2009	LB30	43.6	219.2	403.2	171												837.0
Subtotal			**43.6**	**219.2**	**403.2**	**171.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**837.0**
Croatia	2009	CCG3		12.7	171.8	163.4												347.9
	2011	OCGT					2.9	27.0										29.9
	2012	CSUB					22.6	134.6	72.6									229.8
	2013	CCG3						6.3	85.9	81.7								173.9
	2015	CCG5								23.7	141.2	76.1						241.0
	2017	CSUB										22.6	134.6	72.6				229.8
	2018	CCG3											6.3	85.9	81.7			173.9
	2020	OCGT														2.9	27.0	29.9
Subtotal			**0.0**	**12.7**	**171.8**	**163.4**	**25.5**	**167.9**	**158.5**	**105.4**	**141.2**	**98.7**	**140.9**	**158.5**	**81.7**	**2.9**	**27.0**	**1456.1**

Non-Discounted Annual Construction Costs for New Capacity (2005 Price :Level) Continued

Macedonia	2010	B4IL	7.9	32.7	73.8	76.6	24.8											215.8
	2010	CHP			9.6	57.0	30.7											97.3
	2010	GT60				7.0	15.2											22.2
	2014	GT12								11.7	25.4							37.1
	2014	LPOL						1.9	9.3	17.1	7.3							35.6
	2016	GT60										7.0	15.2					22.2
	2016	MAT2							0.7	3.4	12.3	18.6	6.6					41.6
	2016	BMOS								2.3	11.8	21.7	9.2					45.0
	2019	GT12													11.7	25.5		37.2
	2019	GRAD											8.1	40.7	75.0	31.8		155.6
	2019	CBRL									4.5	11.2	34.4	59.0	39.4	11.0		159.5
	2019	SPI2												1.3	17.3	16.4		35.0
	2019	GALI								4.6	8.9	32.3	39.9	64.4	40.6	10.1		200.8
Subtotal			**7.9**	**32.7**	**83.3**	**140.6**	**70.7**	**1.9**	**10.0**	**39.1**	**70.2**	**90.7**	**113.4**	**165.4**	**184.0**	**94.8**	**0.0**	**1104.8**
Montenegro	2010	KOST	9.7	40.4	91.0	94.4	30.5											266.0
	2011	CCHP				8.1	48.1	25.9										82.1
	2011	OC10					2.9	27.1										30.0
	2014	CCHP							4.0	24.0	13.0							41.0
Subtotal			**9.7**	**40.4**	**91.0**	**102.5**	**81.5**	**53.0**	**4.0**	**24.0**	**13.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**419.1**
Romania	2007	CER2	508.6	65.9														574.5
	2008	CCHP	4.0	24.0	13.0													41.0
	2008	CC30	6.3	85.7	81.5													173.5
	2009	CC30		6.3	85.7	81.5												173.5
	2012	CC30					6.3	85.7	81.5									173.5
	2013	CCHP						8.1	48.1	25.9								82.1
	2013	CC30						6.3	85.7	81.5								173.5
	2014	CC30							6.3	85.7	81.5							173.5
	2015	CCHP								4.0	24.0	13.0						41.0
	2015	CC30								6.3	85.7	81.5						173.5
	2016	CC30									6.3	85.7	81.5					173.5
	2017	CER3								36.7	152.5	343.9	356.9	115.4				1005.4
	2018	CCHP											4.0	24.0	13.0			41.0
	2018	RORN											29.6	176.7	95.3			301.6
	2019	CCHP												8.1	48.1	25.9		82.1
	2019	LB30											15.8	79.6	146.4	62.1		303.9
	2020	LP50												27.9	140.3	258.2	109.5	535.9
Subtotal			**518.9**	**181.9**	**180.2**	**81.5**	**6.3**	**100.1**	**221.6**	**240.1**	**350.0**	**524.1**	**487.8**	**431.7**	**443.1**	**346.2**	**109.5**	**4223.0**

Non-Discounted Annual Construction Costs for New Capacity (2005 Price :Level) Continued

Serbia	2009	CCG3		6.3	85.9	81.7											173.9
	2010	KOLB		11.2	56.1	103.3	43.8										214.4
	2011	KOLB			11.2	56.1	103.3	43.8									214.4
Subtotal			**0.0**	**17.5**	**153.2**	**241.1**	**147.1**	**43.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**602.7**
Unmik	2010	K1B3		15.3	77.0	141.6	60.1										294.0
	2011	K2B3			45.1	226.7	417.1	176.9									865.8
	2011	K3B3			14.2	71.3	131.2	55.7									272.4
	2018	K1B3										7.7	38.5	70.8	30.0			147.0
Subtotal			**0.0**	**15.3**	**136.3**	**439.6**	**608.4**	**232.6**	**0.0**	**0.0**	**0.0**	**7.7**	**38.5**	**70.8**	**30.0**	**0.0**	**0.0**	**1579.2**
Total			**580**	**520**	**1,235**	**1,553**	**1,259**	**662**	**446**	**469**	**690**	**862**	**993**	**1,174**	**994**	**522**	**164**	**12,122.5**

3.9.3 Scenario B Results

In the previous section, Scenario A results were presented. Each jurisdiction was expected to meet its own demand, based on supplies within the jurisdiction. A representative least-cost plan was developed for each jurisdiction. As an opposite alternative, Scenario B analyses all jurisdictions in a fully integrated regional power system. Scenario B corresponds to an ideal scenario with no transmission interconnection constraints or limits in optimal unit dispatch to meet regional demand.

To assess the economic impacts of various rehabilitation scenarios, several cases are analysed, using the WASP model. Case 1 uses the rehabilitation program given by the utilities. No analysis was performed to test the economic viability of the proposed rehabilitation programs before running the WASP model.

For Case 2, the economics of the rehabilitation programs are first tested through the use of screening curves. Screening curves are constructed for all rehabilitated units to provide an assessment of their annualised costs of electricity generation. Each curve is compared to a composite screening curve for new capacity to estimate the attractiveness of the rehabilitated plant.

Details are presented in Appendix 12. In Case 2A1, the total rehabilitation was reduced from 11,574 MW to 6.105 MW. In Case 2A2, the capacity was reduced to 9,916 MW. A fourth case (Case 2B) was developed to postpone the rehabilitation planned for 2005-2007 by one or two years.

The results are summarised in Table 39. Case 1A, based on the rehabilitation program given by the utilities, has a total net present value of 34.09 billion Euros. Case 2A1 shows a reduction in total net present value of 2.19 billion Euros or 6.4%, when compared to Case 1A. Reductions in Case 2A2 and Case 2B are much smaller, 331 and 455 million Euros, respectively.

Table 39: Comparison of Scenario B Results

	Rehabilitation (MW)	New Capacity (MW)	Net Present Value (Million Euros)
Case 1A	11,574	11,000	34,092
Case 2A1	6,105	15,202	31,894
Case 2A2	9,916	11,884	33,761
Case 2B	9,916	11,884	33,637

Table 40 and Table 41 summarise the yearly expansion plans for the units planned for rehabilitation (Table 40) and new capacity additions (Table 41) under the four cases (Cases 1 and 2s) analysed, to facilitate comparison of the year-by-year differences.

Table 40: Yearly Comparison of Plants Planned for Rehabilitation

Year	Rehabilitation Comparison			
	Case1A	**Case2A1**	**Case2A2**	**Case2B**
2005				
2006	Maritsa East 3 (189 MW)x2 Maritsa East 2 (148 MW) Ruse 3 (100 MW) Novi Sad1 (100 MW) Zrenjanin (100 MW)		Maritsa East 3 (189 MW)x2 Maritsa East 2 (148 MW) Ruse 3 (100 MW) Novi Sad 1 (100 MW) Zrenjanin (100 MW)	
2007	Fierza (58 MW) Balsh (11MW) Tuzla 5 (182 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Turceni 5 (272 MW) Deva 1 (167 MW) Nikola Tesla A4 (280 MW) Kostolac A1 (90 MW) Novi Sad21 (108 MW)	Maritsa East 2 (148 MW) Tuzla 5 (182 MW) Turceni 5 (272 MW) Nikola Tesla A4 (280 MW)	Tuzla 5 (182 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Turceni 5 (272 MW) Nikola Tesla A4 (280 MW) Kostolac A1 (90 MW) Novi Sad 2 (108 MW)	Maritsa East 3 (189 MW)x2 Maritsa East 2 (148 MW) Ruse 3 (100 MW) Novi Sad 1 (100 MW) Zrenjanin (100 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Turceni 5 (272 MW) Nikola Tesla A4 (280 MW)
2008	Tuzla 6 (198 MW) Kakanj 6 (100 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Rovinari 3 (278 MW) Galati 3 (92 MW) Deva 2 (167 MW) Nikola Tesla A6 (280 MW)	Maritsa East 2 (148 MW) Nikola Tesla A6 (280 MW)	Tuzla 6 (198 MW) Kakanj 6 (100 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Rovinari 3 (278 MW) Nikola Tesla A6 (280 MW)	Kostolac A1 (90 MW) Novi Sad 2 (108 MW) Tuzla 5 (182 MW) Tuzla 6 (198 MW) Kakanj 6 (100 MW) Maritsa East 2 (148 MW) Rovinari 3 (278 MW) Nikola Tesla A6 (280 MW)
2009	Gacko (276 MW) Maritsa East 2 (148 MW) Maritsa East 2 (185 MW) Ruse 4 (100 MW) Turceni 6 (272 MW) Isalnita 7 (266 MW) Paroseni 4 (120 MW)	Maritsa East 2 (148 MW) Ruse 4 (100 MW) Turceni 6 (272 MW	Maritsa East 2 (148 MW) Maritsa East 2 (185 MW) Ruse 4 (100 MW) Turceni 6 (272 MW) Isalnita 7 (266 MW) Paroseni 4 (120 MW)	Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Maritsa East 2 (185 MW) Ruse 4 (100 MW) Turceni 6 (272 MW) Isalnita 7 (266 MW) Paroseni 4 (120 MW)
2010	Bobov Dol 1 (198 MW) Varna 1 (200 MW) Ruse 1 (25 MW) Turceni 3 (272 MW) Galati 4 (50 MW) Nikola Tesla A1 (191 MW) Deva 4 (167 MW)	Varna 1 (200 MW) Nikola Tesla A1 (191 MW) Turceni 3 (272 MW)	Bobov Dol 1 (198 MW) Varna 1 (200 MW) Turceni 3 (272 MW) Nikola Tesla A1 (191 MW)	Bobov Dol 1 (198 MW) Varna 1 (200 MW) Turceni 3 (272 MW) Nikola Tesla A1 (191 MW)
2011	Ugljevik (279 MW) Bobov Dol 2 (198 MW) Varna 2 (200 MW) Ruse 2 (25 MW) Pljevlja (191 MW) Negotino (197 MW) Rovinari 5 (278 MW) Nikola Tesla A2 (191 MW)	Varna 2 (200 MW) Nikola Tesla A2 (191 MW)	Bobov Dol 2 (198 MW) Varna 2 (200 MW) Negotino (197 MW) Rovinari 5 (278 MW) Nikola Tesla A2 (191 MW)	Bobov Dol 2 (198 MW) Varna 2 (200 MW) Negotino (197 MW) Rovinari 5 (278 MW) Nikola Tesla A2 (191 MW)
2012	Bobov Dol 3 (198 MW)	Varna 3 (200 MW)	Bobov Dol 3 (198 MW)	Bobov Dol 3 (198 MW)

Year	Rehabilitation Comparison			
	Case1A	Case2A1	Case2A2	Case2B
	Varna 3 (200 MW) Ruse 5 (25 MW) Nikola Tesla B1 (580 MW)	Nikola Tesla B1 (580 MW)	Varna 3 (200 MW) Ruse 5 (25 MW) Nikola Tesla B1 (580 MW)	Varna 3 (200 MW) Ruse 5 (25 MW) Nikola Tesla B1 (580 MW)
2013	Varna 4 (200 MW) Ruse 6 (25 MW) Oslomej (109 MW) Galati 5 (92 MW)	Varna 4 (200 MW)	Varna 4 (200 MW) Ruse 6 (25 MW) Oslomej (109 MW) Galati 5 (34 MW)	Varna 4 (200 MW) Ruse 6 (25 MW) Oslomej (109 MW) Galati 5 (34 MW)
2014	Varna 5 (200 MW) Galati 6 (92 MW) Nikola Tesla B2 (580 MW)	Varna 5 (200 MW) Nikola Tesla B2 (580 MW)	Varna 5 (200 MW) Nikola Tesla B2 (580 MW)	Varna 5 (200 MW) Nikola Tesla B2 (580 MW)
2015	Varna 6 (200 MW) Bitola 1 (207 MW)	Varna 6 (200 MW) Bitola 1 (207 MW)	Varna 6 (200 MW) Bitola 1 (207 MW)	Varna 6 (200 MW) Bitola 1 (207 MW)
2016	Kostolac B1 (320 MW)	Kostolac B1 (320 MW)	Kostolac B1 (320 MW)	Kostolac B1 (320 MW)
2017	Bitola 2 (207 MW)	Bitola 2 (207 MW)	Bitola 2 (207 MW)	Bitola 2 (207 MW)
2018	Kostolac B1 (320 MW)	Kostolac B1 (320 MW)	Kostolac B1 (320 MW)	Kostolac B1 (320 MW)
2019				
2020	Bitola 3 (207 MW)	Bitola 3 (207 MW)	Bitola 3 (207 MW)	Bitola 3 (207 MW)
Total	11,574 MW	6,105 MW	9,916 MW	9,916 MW

Table 41: Yearly Comparison of New Capacity Additions

Year	Candidates Comparison			
	Case1A	**Case2A1**	**Case2A2**	**Case2B**
2005				
2006	Bucuresti Sud (100MW)	Bucuresti Sud (100MW)	Bucuresti Sud (100MW)	Bucuresti Sud (100MW)
2007	Bucuresti Sud (100MW)	Bucuresti Sud (100MW) Kolubara B (320 MW)	Bucuresti Sud (100MW)	Bucuresti Sud (100MW)
2008	Bucuresti Vest (100MW)	Bucuresti Vest (100MW) Maritsa East 1 (275 MW)x2 Kolubara B (320 MW) Kosovo B3 (274 MW)	Bucuresti Vest (100MW) Maritsa East 1 (275 MW)x2	Bucuresti Vest (100MW) Maritsa East 1 (275 MW)x2
2009	Vlora (132 MW) Maritsa East 1 (275 MW) x2	Vlora (132 MW) Cernavoda 2 ((664 MW) Lignite Subcritical (450 MW)x2	Vlora (132 MW) Combined cycle (288 MW) Kolubara B (320 MW)	Vlora (132 MW) Combined cycle (288 MW Kolubara B (320 MW)
2010	Bucuresti Vest (100MW) Cernavoda 2 (664 MW) Lignite Subcritical (450 MW) Kolubara B (320 MW)	Bucuresti Vest (100MW) Cernavoda 3 ((664 MW) CCHP (86 MW) Combined cycle (288 MW) Combined cycle (480 MW) Kosovo B4 (274 MW)	Bucuresti Vest (100MW) Cernavoda 2 ((664 MW) Combined cycle (288 MW) Kolubara B (320 MW) Kosovo B3 (274 MW)	Bucuresti Vest (100MW) Cernavoda 2 ((664 MW) Combined cycle (288 MW Kolubara B (320 MW) Kosovo B3 (274 MW)
2011	Kolubara B (320 MW)	Belene (930MW) Kosovo B5 (274 MW)	Combined cycle (288 MW) Kosovo B4 (274 MW)	Cernavoda 3 (664 MW)
2012	Combined cycle (288 MW)	CCHP (86 MW) Combined cycle (288 MW)	Lignite Subcritical (450 MW)	
2013	Cernavoda 3 (664 MW) CCHP (86 MW) Kosovo B3 (274 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (288 MW) Combined cycle (480 MW)x2 Lignite Subcritical (450 MW)	Belene (930MW) Cernavoda 3 (664 MW)	Belene (930MW) Combined cycle (288 MW Kosovo B4 (274 MW) Lignite Subcritical (450 MW)
2014	CCHP (86 MW)	Combined cycle (288 MW)		
2015	Combined cycle (288 MW) Combined cycle (480 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Kosovo B6 (274 MW) Lignite Subcritical (450 MW)x2	CCHP (86 MW) Combined cycle (480 MW) Kosovo B5 (274 MW) Lignite Subcritical (450 MW)	Combined cycle (480 MW Kosovo B5 (274 MW) Lignite Subcritical (450 MW)
2016	CCHP (86 MW) Combined cycle (480 MW)	Combined cycle (288MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (480 MW)x2	CCHP (86 MW)x2 Combined cycle (480 MW
2017	Belene (930MW) Combined cycle (480 MW)	Combined cycle (480 MW)x2 Kosovo B7 (274 MW)	CCHP (86 MW) Kosovo B6 (274 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Kosovo B6 (274 MW) Combined cycle (480 MW Lignite Subcritical (450 MW)
2018	Combined cycle (288 MW) Kosovo B4 (274 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (288 MW) Lignite Subcritical (450 MW)	Combined cycle (480 MW) Lignite Subcritical (450 MW)	Combined cycle (480 MW Lignite Subcritical (450 MW)
2019	CCHP (86 MW) Combined cycle (288 MW) Kosovo B5 (274 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (288 MW) Combined cycle (480 MW) Kosovo B8 (274 MW)	CCHP (86 MW) Combined cycle (288 MW)x2 Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (288 MW)x2 Lignite Subcritical (450 MW)
2020	Combined cycle (288 MW) Kosovo B6 (274 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (480 MW) Lignite Subcritical (450 MW)	CCHP (86 MW) Combined cycle (480 MW) Combined cycle (288MW)	CCHP (86 MW) Combined cycle (480 MW Combined cycle (288MW)
Total	11,000 MW	15,202 MW	11,884 MW	11,884 MW

3.9.4 Scenario C Results

3.9.4.1 *Introduction*

To reflect existing constraints in the regional electricity market, Scenario C is studied based on the results of Scenario B (unconstrained regional market), and a detailed hourly market simulation for two years (2010 and 2015) using the GTMax model. Actual operating conditions are determined, based on the candidate capacity projects identified as regional priorities in Scenario B, as well as the proposed regional transmission interconnections.

Scenario B "Case 1A", presented previously, is selected as the Reference Case for Scenario C. It includes the life extension and rehabilitation programs as scheduled by the utilities.

In addition to the WASP results described in the previous section, an extensive analysis is made on this Reference Case by using the GTMax model that allows a detailed hourly optimization of each power system within a regional power market. GTMax takes into account not only the chronological hourly load demands and units available for power generation, but also the maximum transfer capabilities of the transmission interconnections between generation points and load centres, between load centres, and between individual power systems. GTMax also optimises the marginal production costs in each of the utility systems. Appendix 11 describes the GTMax model and the major input data and assumptions.

To reflect variations in hydrological cycles, the GTMax model is run for wet-, average-, and dry-year conditions. Since the model is run on a weekly basis, four typical weeks are selected for years 2010 and 2015: the peak week (3rd week of January), and three other weeks representative of seasonal variations (3rd week of April, July and September). Regional load shapes for these four weeks are shown in Appendix 11.

To further analyse the need to expand or upgrade regional transmission interconnections, the results of the GTMax model were further tested in the PSS/E model. An agreement was reached with the SECI Transmission group so that they could run several cases. The PSS/E model is a very detailed model that analyses the basic functions of power system performance simulation work, namely:

- Data handling, updating, and manipulation;
- Power Flow;
- Fault Analysis; and
- Dynamic Simulation + Extended Term Simulation.

The GTMax results for the regional peak hour of 2010 and 2015 is used in the PSS/E model to evaluate the proposed transmission interconnections for 2010 and 2015. Details on the PSS/E model and the results are presented in Appendix 13.

It is important to note that this is the first time that a complete set of integrated regional data (load demand forecasts, existing generation, proposed rehabilitation and expansion plans, as well as existing and proposed transmission interconnections) has been analysed consistently through different sets of models.

After a detailed analysis of the Reference Case through the GTMax and PSS/E models, a series of sensitivity cases is run. Table 42 summarises the cases analysed.

Table 42: List of Scenario C Cases

Scenario C Cases	Load Forecast	Gas Price Forecast	Rehab Plan	"Forced" Hydro
Reference Case	Medium	Medium	Utility	NO
Forced Hydro	Medium	Medium	Utility	YES
High Gas Price	Medium	High	Utility	YES
High Demand	High	Medium	Utility	YES
Low Demand	Low	Medium	Utility	NO
Full Rehab	Medium	Medium	Utility + Full Rehab	NO
Nuclear	Medium	Medium	Utility	NO
Increase Construction Cost	Medium	Medium	Utility	NO
Discount Rate	Medium	Medium	Utility	NO

Units already under construction or fully committed by the utilities are maintained in the Scenario C regional expansion plans. These units are shown in Table 43.

Table 43: Units Under Construction or Committed By Utilities

Jurisdiction	**Unit Name**	**Net Capacity (MW)**	**First Year of Operation**
Romania	Bucuresti Sud	100	2006
Romania	Bucuresti Sud	100	2007
Romania	Bucuresti West	100	2008
Romania	Bucuresti West	100	2010
Bulgaria	Maritsa East 1	2x275	2009
Albania	Vlora	132	2009
Total		1,082	

The Scenario C analysis is performed mostly for the medium load forecast with a sensitivity analysis performed for the low and high demand forecasts. The expected regional load forecasts are presented in Table 44 and Table 45.

Table 44: Regional Annual Peak Load Forecast (MW)

	Year 2005	Year 2010	Year 2020
Medium Demand	27,882	29,649	38,049
High Demand	28,117	31,022	43,359
Low Demand	26,927	26,573	32,604

The average annual growth rate is 2.1% for the medium forecast, 2.9% for the high forecast and 1.3% for the low demand forecast.

Table 45: Regional Annual Energy Forecast (GWh)

Jurisdiction	Year 2005	Year 2010	Year 2020
Medium Demand	166,451	182,606	235,727
High Demand	167,815	191,259	269,155
Low Demand	160,837	163,763	201,389

The 2020 annual energy high demand forecast is 14% greater than the medium demand. The 2020 low demand is 15% lower than the medium demand.

The Reference Case reflects the rehabilitation program as given by the utilities. No adjustments are made to the planned timing of rehabilitation. Rehabilitation costs were obtained from the utilities and reviewed and updated by the SEEC Environmental Team. Details of these costs are shown in Appendix 9 and in SEEC's report entitled "GIS – Implications for Investments in Environmental Protection".

Under this Case, rehabilitation includes technical rehabilitation (life extension) and full environmental compliance (particulate, NOx and SOx controls) with EC regulations (Directive 2001/80/EC) for Romania and Bulgaria. For the other jurisdictions, rehabilitation includes technical rehabilitation and partial environmental compliance (particulate and NOx) for plants planned for rehabilitation.

The list of rehabilitated plants, timing of rehabilitation and costs are shown in Appendix 9. The total capacity of the plants planned for rehabilitation is 11,574 MW. The investment cost is estimated at 5.9 billion Euros (2005 price level).

3.9.4.2 *WASP Results*

Results of the 2005-2020 expansion plan are shown in Table 46. In addition to the 11,574 MW of rehabilitated units, 11,000 MW of new capacity is added during the study period to maintain a LOLP of less than one day per year. The new net capacity additions include 1,082 MW that is already under construction or fully committed by the utilities, as shown in Table 2. In addition, 2,258 MW of nuclear (Cernavoda 2 in 2010, Cernavoda 3 in 2013, and Belene 1 in 2017), 3,796 MW of Kosovo lignite, 640 MW of Kolubara lignite, 344 MW of CHP plants, and 2,880 MW of combined cycle gas-fired generation are added to the regional system.

The results show that, on a regional level, there is some excess of existing capacity in the first 3 years (2005-2007) as shown by LOLPs equal to 0.0. The WASP model starts bringing new capacity from the candidate plants in year 2008 and thereafter.

In addition to the plants shown in Table 46, WASP results show that, for the period 2005-2010, the following new capacity would be added to the regional power system:

- Cernavoda nuclear unit #2;
- Kolubara lignite unit #1; and
- One 500-MW Kosovo lignite plant.

In the period 2011-2015, the following units would be added:

- Cernavoda nuclear unit #3;
- Kolubara lignite unit #2;
- One 300-MW and two 500-MW Kosovo lignite plants;
- Two 100-MW CHP plants; and
- Two 300-MW and one 500-MW combined cycle plants.

In the period 2016-2020, the following units would be added:

- Belene nuclear unit #1;
- Three 300-MW and three 500-MW Kosovo lignite plants;
- Two 100-MW CHP plants; and
- Three 300-MW and two 500-MW combined cycle plant.

The total net present value of the total system investment and operating costs amounts to 34.09 billion Euros. This includes the net present value of the capital costs for the planned rehabilitation of existing units. This is computed in a separate spreadsheet (see Appendix 9). The net present value of the investment for planned rehabilitation is 4.12 billion Euros.

Table 46: Reference Case Capacity Expansion Plan and LOLP

Year	Peak Load (MW)	Capacity Additions		Total System Net Capacity (MW)	LOLP (%)
		Rehabilitation	New Plants		
2005	27,882			42,817	0.000
2006	28,202	Maritsa East 3 (189 MW) x2 Maritsa East 2 (148 MW) Ruse 3 (100 MW) Novi Sad 1 (100 MW) Zrenjanin (100 MW)	Bucuresti Sud (100MW)	42,217	0.000
2007	28,553	Fierza (58 MW) Balsh (11MW) Tuzla 5 (182 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Turceni 5 (272 MW) Deva 1 (167 MW) Nikola Tesla A4 (280 MW) Kostolac A1 (90 MW) Novi Sad 2 (108 MW)	Bucuresti Sud (100MW)	40,632	0.000
2008	28,927	Tuzla 6 (198 MW) Kakanj 6 (100 MW) Maritsa East 3 (189 MW) Maritsa East 2 (148 MW) Rovinari 3 (278 MW) Galati 3 (92 MW) Deva 2 (167 MW) Nikola Tesla A6 (280 MW)	Bucuresti Vest (100MW)	40,621	0.118

Reference Case Capacity Expansion Plan and LOLP (Continued)

Year	Peak Load (MW)	Capacity Additions		Total System Net Capacity (MW)	LOLP (%)
		Rehabilitation	New Plants		
2009	29,234	Gacko (276 MW) Maritsa East 2 (148 MW) Maritsa East 2 (185 MW) Ruse 4 (100 MW) Turceni 6 (272 MW) Isalnita 7 (266 MW) Paroseni 4 (120 MW)	Vlora (132 MW) Maritsa East 1 (275 MW)x2	41,096	0.188
2010	29,649	Bobov Dol 1 (198 MW) Varna 1 (200 MW) Ruse 1 (25 MW) Turceni 3 (272 MW) Galati 4 (50 MW) Nikola Tesla A1 (191 MW) Deva 4 (167 MW)	Bucuresti Vest (100MW) Cernavoda 2 (664 MW) Lignite Subcritical (450 MW) Kolubara B (320 MW)	41,423	0.116
2011	30,242	Ugljevik (279 MW) Bobov Dol 2 (198 MW) Varna 2 (200 MW) Ruse 2 (25 MW) Pljevlja (191 MW) Negotino (197 MW) Rovinari 5 (278 MW) Nikola Tesla A2 (191 MW)	Kolubara B (320 MW)	42,096	0.000
2012	30,864	Bobov Dol 3 (198 MW) Varna 3 (200 MW) Ruse 5 (25 MW) Nikola Tesla B1 (580 MW)	Combined cycle (288 MW)	42,897	0.000

Reference Case Capacity Expansion Plan and LOLP (Continued)

Year	Peak Load (MW)	Capacity Additions		Total System Net Capacity (MW)	LOLP (%)
		Rehabilitation	New Plants		
2013	31,535	Varna 4 (200 MW) Ruse 6 (25 MW) Oslomej (109 MW) Galati 5 (92 MW)	Cernavoda 3 (664 MW) CCHP (86 MW) Kosovo B3 (274 MW) Lignite Subcritical (450 MW)	43,053	0.224
2014	32,282	Varna 5 (200 MW) Galati 6 (92 MW) Nikola Tesla B2 (580 MW)	CCHP (86 MW)	43,917	0.037
2015	33,151	Varna 6 (200 MW) Bitola 1 (207 MW)	Combined cycle (288 MW) Combined cycle (480 MW) Lignite Subcritical (450 MW)	44,425	0.233
2016	34,072	Kostolac B1 (320 MW)	CCHP (86 MW) Combined cycle (480 MW)	45,311	0.225
2017	35,026	Bitola 2 (207 MW)	Belene (930MW) Combined cycle (480 MW)	46,194	0.149
2018	36,002	Kostolac B1 (320 MW)	Combined cycle (288 MW) Kosovo B4 (274 MW) Lignite Subcritical (450 MW)	47,225	0.064
2019	37,024		CCHP (86 MW) Combined cycle (288 MW) Kosovo B5 (274 MW) Lignite Subcritical (450 MW)	48,116	0.132
2020	38,049	Bitola 3 (207 MW)	Combined cycle (288 MW) Kosovo B6 (274 MW) Lignite Subcritical (450 MW)	49,128	0.113
Total		**11,574 MW**	**11,000 MW**		

3.9.4.3 *GTMax Results*

The GTMax model is first run for 2010 and 2015 for the Peak Week (Week 3 in January) under average hydrological conditions. The results are shown in Table 47.

Table 47: GTMax Results Under Average Hydrologic Conditions

Regional Market Operation - 2010 – Average Hydrology - week 3								
System	Total Demand (GWh)	Hydro Generation (GWh)	Thermal Generation (GWh)	Total Generation (GWh)	Import (GWh)	Export (GWh)	Generation Costs (€1000)	Average LMP (€/MWh)
Albania	175.8	86.9	23.5	110.4	63.5	0.0	681	25.9
B&H	269.2	151.7	132.8	284.5	0.0	15.3	3,116	25.9
Bulgaria	899.0	53.6	1074.7	1128.3	0.0	229.3	16,275	25.9
Croatia	431.2	130.0	125.3	255.3	175.9	0.0	1,712	25.9
Macedonia	172.2	18.7	122.6	141.3	30.9	0.0	1,411	25.9
Montenegro	100.9	49.1	0.0	49.1	54.8	0.0	0	25.9
Romania	1145.3	240.1	886.7	1126.9	18.4	0.0	14,158	25.9
Serbia	816.8	218.5	674.2	892.7	0.0	78.8	11,540	25.9
UNMIK	158.0	1.8	176.4	178.2	0.0	20.2	1,408	25.9
Total	**4166.6**	**950.4**	**3216.2**	**4166.6**	**343.5**	**343.5**	**50,301**	**-**

Regional Market Operation – 2015 – Average Hydrology - week 3								
System	Total Demand (GWh)	Hydro Generation (GWh)	Thermal Generation (GWh)	Total Generation (GWh)	Import (GWh)	Export (GWh)	Generation Costs (€1000)	Average LMP (€/MWh)
Albania	209.8	86.9	23.5	110.4	99.4	0.0	681	22.6
B&H	312.5	151.7	128.3	279.9	32.6	0.0	3,020	22.6
Bulgaria	970.8	53.8	1145.5	1199.3	0.0	228.5	17,695	22.6
Croatia	502.9	130.0	252.8	382.8	120.1	0.0	4,271	22.6
Macedonia	201.5	18.7	117.1	135.7	65.8	0.0	1,675	22.6
Montenegro	101.9	49.1	32.1	81.2	23.7	0.0	884	22.6
Romania	1330.3	240.1	942.3	1182.4	147.8	0.0	12,938	22.6
Serbia	871.8	219.2	692.5	911.6	0.0	42.7	11,577	22.6
UNMIK	156.3	1.8	372.6	374.4	0.0	218.2	3,114	22.6
Total	**4657.7**	**951.2**	**3706.6**	**4657.8**	**489.4**	**489.4**	**55,856**	**-**

Note: LMP = fuel + variable O&M Costs

The weekly results show that Bulgaria remains a main exporter to the region for both 2010 and 2015, with UNMIK becoming also a main exporter in 2015. Due to an increase in demand, the weekly generation costs increased from €50.3 million in 2010 to €55.9 million in 2015.

Locational marginal prices (LMPs) are constant throughout the region. This result indicates that there are no transmission congestions when running the GTMax model. Without congestions, LMPs are computed for each hour from the fuel and variable O&M costs of the cheapest unit able to generate an additional MW. It is interesting to note that the weekly average LMPs decreased from €25.9/MWh in 2010 to €22.6/MWh in 2015. This is due to new capacity coming on line between 2010 and 2015 and a cheaper unit available to meet an incremental demand.

The GTMax model is then run under dry and wet hydrologic conditions for the peak week and also for typical weeks in April (Week 16), July (Week 29), and October (Week 42). Details of the results are shown in Appendix 11. Table 48 and Table 49 summarise the weekly hydro and thermal generation.

Table 48: Total Electricity Generation by Period and Hydro Condition
- Regional Market Operation in 2010 -

	Electricity Generation (GWh)		
	Hydro	**Thermal**	**Total**
Dry Hydrological Condition			
Week 3 (January)	**696.9**	**3481.8**	**4178.6**
Week 16 (April)	**922.7**	**2574.7**	**3497.4**
Week 29 (July)	**630.3**	**2622.7**	**3253.0**
Week 42 (October)	**560.7**	**2953.1**	**3513.8**
Estimated Annual	**36,537.8**	**151,219.9**	**187,757.7**
Average Hydrological Condition			
Week 3 (January)	**950.4**	**3216.2**	**4166.6**
Week 16 (April)	**1201.0**	**2276.7**	**3477.7**
Week 29 (July)	**808.4**	**2435.9**	**3244.4**
Week 42 (October)	**702.5**	**2778.7**	**3481.2**
Estimated Annual	**47,610.2**	**139,197.7**	**186,808.0**
Wet Hydrological Condition			
Week 3 (January)	**1119.4**	**3045.3**	**4164.7**
Week 16 (April)	**1349.3**	**2126.4**	**3475.7**
Week 29 (July)	**924.8**	**2322.4**	**3247.2**
Week 42 (October)	**869.3**	**2606.6**	**3475.9**
Estimated Annual	**55,416.3**	**131,309.6**	**186,726.0**

Annual generation is computed from the weekly generation by multiplying each weekly generation by 13 (52 weeks divided by four seasons).

The hydro generation data also reflects pumped storage generation. There is about a 52% increase in hydro generation between dry and wet hydrological conditions.

In 2010, hydro generation is expected to vary between 19% and 30% of the total generation, with an average of 25%.

Table 49: Total Electricity Generation by Period and Hydro Condition - Regional Market Operation in 2015 -

	Electricity Generation (GWh)		
	Hydro	Thermal	Total
Dry Hydrological Condition			
Week 3 (January)	708.6	3976.5	4685.1
Week 16 (April)	927.9	3006.7	3934.6
Week 29 (July)	642.3	3030.0	3672.2
Week 42 (October)	562.5	3378.4	3940.9
Estimated Annual	36,936.7	174,090.6	211,027.3
Average Hydrological Condition			
Week 3 (January)	951.2	3706.6	4657.8
Week 16 (April)	1202.5	2707.1	3909.7
Week 29 (July)	821.4	2843.4	3664.8
Week 42 (October)	715.6	3208.6	3924.2
Estimated Annual	47,979.8	162,054.6	210,034.4
Wet Hydrological Condition			
Week 3 (January)	1122.3	3536.5	4658.8
Week 16 (April)	1349.5	2556.4	3905.9
Week 29 (July)	943.7	2732.4	3676.0
Week 42 (October)	884.4	3037.3	3921.7
Estimated Annual	55,899.4	154,213.6	210,113.1

In 2015, hydro generation is expected to vary between 18% and 27% of the total generation, with an average of 23%.

Figure 8 shows the expected annual power exchanges between each jurisdiction.

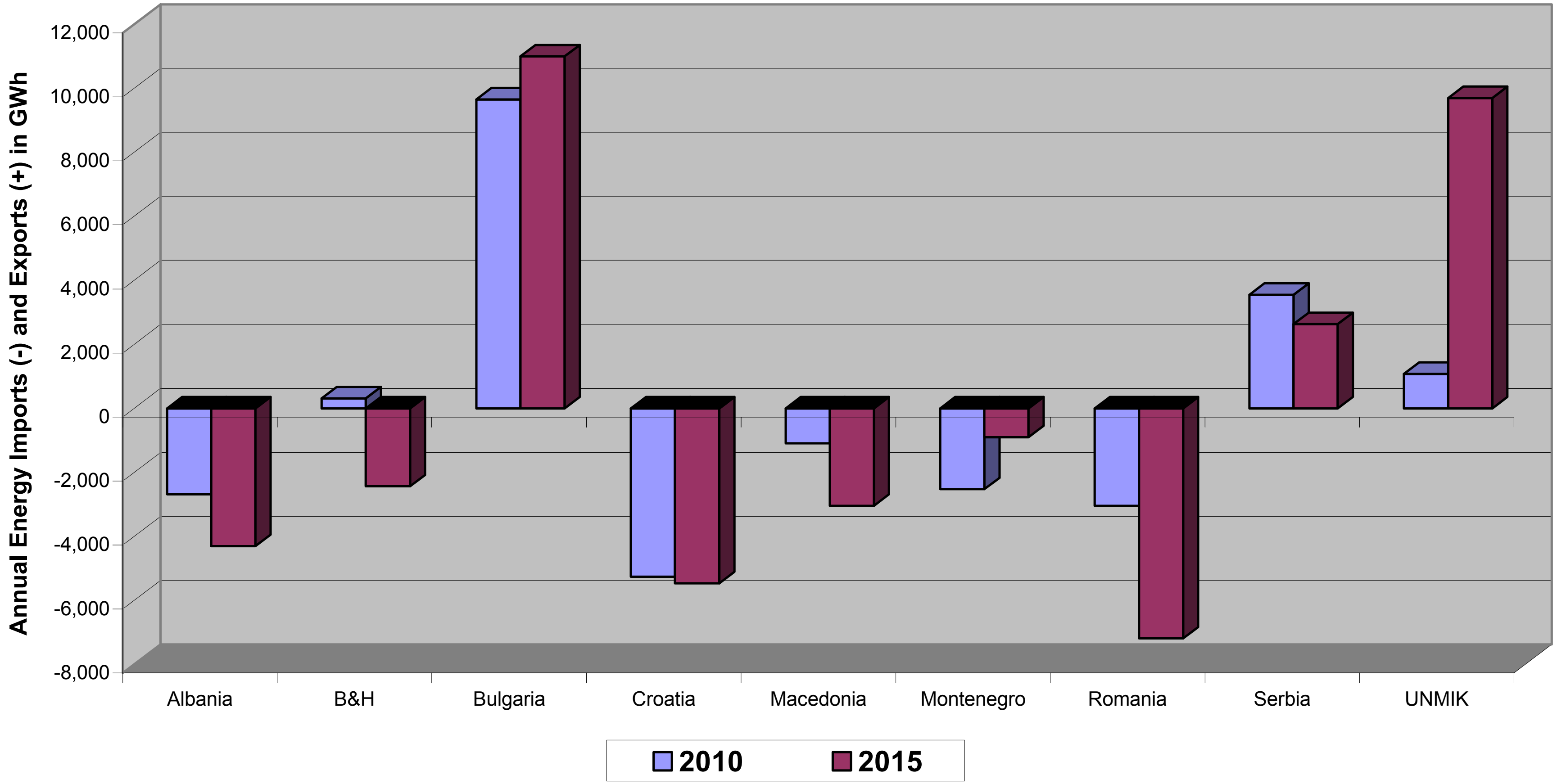


Figure 8: Internal Regional Power Exchange

Table 50 summarises the operating costs (fuel and variable O&M) for each week. For 2010, the estimated annual costs vary from €2.0 billion in a wet year to €2.5 billion in a dry year. In 2015, the range is from €2.3 to €2.8 billion.

Table 50: Total Operating Costs for the Regional Market Operation in 2010 and 2015

	Operating Costs Under Different Hydrological Conditions (€'000)		
	Dry	**Average**	**Wet**
Regional Market Operation in 2010			
Week 3 (January)	58,466	50,301	45,797
Week 16 (April)	40,294	33,174	30,502
Week 29 (July)	44,311	39,918	37,665
Week 42 (October)	51,079	44,627	40,594
Estimated Annual	2,523,952	2,184.264	2,009,253
Regional Market Operation in 2015			
Week 3 (January)	63,536	55,856	52,238
Week 16 (April)	47,304	40,417	37,550
Week 29 (July)	48,717	43,386	41,338
Week 42 (October)	53,873	49,960	46,590
Estimated Annual	2,774,564	2,465,048	2,310,299

Table 51 summarises the average weekly LMPs under 2010 and 2015 and under the three hydrological conditions. No transmission congestions were observed when running the GTMax model for these various cases. The average weekly LMPs were uniform throughout the region. There is however quite a variation from week to week and from dry to average and wet conditions.

Table 51: Average LMP for the Regional Market Operation in 2010 and 2015

	Weekly LMP Under Different Hydrological Conditions (€/MWh)		
	Dry	**Average**	**Wet**
Regional Market Operation in 2010			
Week 3 (January)	30.9	25.9	22.8
Week 16 (April)	28.7	17.7	17.1
Week 29 (July)	31.9	28.0	27.8
Week 42 (October)	35.0	27.3	27.2
Regional Market Operation in 2015			
Week 3 (January)	27.2	22.6	22.6
Week 16 (April)	25.0	17.8	16.9
Week 29 (July)	28.2	25.5	25.3
Week 42 (October)	29.2	24.8	25.0

Note: LMP = fuel + variable O&M Costs

In 2010, the LMPs vary from €17.1 to €35.0/MWh. In 2015, the range is from €16.9 to €29.2/MWh.

3.9.4.4 *PSS/E Results*

The GTMax output for the peak hour in 2010 and 2015 in dry, average and wet hydrology conditions were used in the PSS/E model to analyse the behaviour of the regional network under each case. The detailed results of these studies are presented in Appendix 13.

Table 52 summarises power losses on a regional level for the various cases analysed. In 2010, the peak demand is projected to be 29,649 MW and losses are estimated to vary between 737 and 757 MW, or about 2.5%. In 2015, the peak is projected to increase to 33,151 MW. The PSS/E model was run for both the 2010 and 2015 topology. In 2015, losses increase to about 3.0% under the 2010 topology. New transmission lines planned for commissioning between 2010 and 2015 have a positive impact on losses, reducing them between 30 and 40 MW. These changes are a consequence of better voltage profile in the region, especially in areas directly influenced by the new transmission interconnections. For example, the new interconnection line Nis-Leskovac-Vranje-Skopje greatly improves voltage profile in southern part of Serbia and the new interconnection lines Podgorica – V.Dejes – Kashar – Elbasan and Kosovo B – V.Dejes – Kashar – Elbasan greatly improve the voltage profile in Albania.

Table 52: Peak Hour - Regional Losses (MW)

Topology	Year 2010			Year 2015		
	Dry	Average	Wet	Dry	Average	Wet
2010	756.9	737.1	741.5	951.6	1,035.1	976.6
2015	-	-	-	909.6	1,006.4	941.8

Table 53 summarises the transmission lines and transformers that are loaded over 80% of their thermal limits. This is an indication on what parts of the transmission network show weak spots and what network reinforcements would be necessary. The analysis of these results shows that the regional transmission network is capable of transferring power from generation facilities to major consumption areas, and that network reinforcement is not necessary under normal operating conditions (without taking n-1 criterion into consideration). In some substations, there is however not enough transformer capacity to supply power from the transmission network. This is a problem of local distribution and should be studied at the local not regional level. Increase in transformer capacity is needed in substations 220/110-kV Fier, Elbasan, Fierza and Kashar in Albania, 400/110 kV Ugljevik in Bosnia and Herzegovina.

Also, it should be noted that level of reactive power consumption in Albania is very high comparing to the other systems and not realistic. This is one of the reasons why the voltage profile in the Albanian network is very close to voltage collapse in some analysed scenarios. Because of the problem with unrealistic reactive power demand, additional reactive power compensators will be required.

Table 53: Overview of high loaded elements in analysed reference cases

		LOAD LEVEL	2010						2015											
		HYDROLOGY	average		dry		wet		average				dry				wet			
		TOPOLOGY							2010		2015		2010		2015		2010		2015	
AREA	ELEMENT	RATING MVA	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%	LOAD MVA	%
									Lines											
ALB	OHL 220 kV AKASHA2-ARRAZH2	270							250	92.6	238	88	275	102	243	89.9	259	96	237	87.8
BUL	OHL 220 kV MI_2_220-ST ZAGORA	228.6															191	83.5	190	83.3
ROM	OHL 220 kV MINTIA-SIBIU	381.1							268	96.5	268	96.4					324	85.1	313	82.2
	OHL 220 kV P.D.F.II-CETATE1	277.4							205	98.6	205	98.5					269	97	268	96.8
	OHL 220 kV P.D.F.A-CETATE1	208.1							236	85.2	232	83.7					206	99	206	98.8
	OHL 220 kV P.D.F.A-RESITA ckt.1	277.4							236	85.2	232	83.7					239	86.2	236	84.9
	OHL 220 kV P.D.F.A-RESITA ckt.2	277.4															239	86.2	236	84.9
	OHL 220 kV LOTRU-SIBIU ckt.1	277.4					276	99.5									304	109	303	109
	OHL 220 kV LOTRU-SIBIU ckt.2	277.4					276	99.5									304	109	303	109
	OHL 220 kV URECHESI-TG.JIU	277.4							278	100	273	98.3					280	101	275	99.3
	OHL 220 kV TG.JIU-PAROSEN	208.1					182	87.3	278	134	273	131					280	135	275	132
	OHL 220 kV BUC.S-B-FUNDENI	320											261	81.6	261	81.4	285	89.2	285	88.9
SRB	OHL 220 kV JBGD3 21-JOBREN2	301							261	86.7	262	87	294	97.5	295	97.9	313	104	313	104
									Transformers											
ALB	TR 220/110 kV AFIERZ2-AFIERZ5 ckt.1	60							51.9	86.5	50.3	83.8	59	98.3	52.1	86.9	54.6	91.1	50.2	83.7
	TR 220/110 kV AFIERZ2-AFIERZ5 ckt.2	60							51.9	86.5	50.3	83.8	59	98.3	52.1	86.9	54.6	91.1	50.2	83.7
	TR 220/110 kV AELBS12-AELBS15 ckt.1	90							78	86.6	74.3	82.5	84.7	94.1	75.4	83.8	81.4	90.5	74.8	83.2
	TR 220/110 kV AELBS12-AELBS15 ckt.2	90							78	86.6	74.3	82.5	84.7	94.1	75.4	83.8	81.4	90.5	74.8	83.2
	TR 220/110 kV AELBS12-AELBS15 ckt.3	90							83.8	93.1	79.8	88.7	91	101	81	90	87.5	97.2	80.4	89.3
	TR 220/110 kV AKASHA2-AKASH25 ckt.1	100							84.1	84.1	82.1	82.1	90.8	90.8	83.5	83.5	87.2	87.2	82.3	82.3
	TR 220/110 kV AKASHA2-AKASH25 ckt.2	100							84.1	84.1	82.1	82.1	90.8	90.8	83.5	83.5			82.3	82.3
	TR 220/110 kV AFIER 2-AFIER 5 ckt.1	120	117	93.7	107	89	117	97.1	138	115	135	113	147	122	137	114	141	118	135	112
	TR 220/110 kV AFIER 2-AFIER 5 ckt.2	90	95.7	106	87.5	97.2	95.5	106	113	126	111	123	120	134	112	125	116	129	110	123
	TR 220/110 kV AFIER 2-AFIER 5 ckt.3	90	91.4	102	83.5	92.8	91.1	101	108	120	106	117	115	128	107	119	110	123	105	117
	TR 220/110 kV ARRAZH 1	100											84.7	84.7			80.3	80.3		
	TR 220/110 kV ARRAZH 2	100											84.7	84.7			80.3	80.3		
	TR 220/110 kV ATIRAN 3	120											98.2	81.9						
B&H	TR 400/110 kV UGLJEVIK	300	255	84.9					255	84.9	253	84.2	242	80.8	241	80.2	270	90	268	89.2
ROM	TR 400/220 kV URECHESI	400							395	98.9	391	97.7					414	104	410	103
	TR 400/220 kV BUC.S-BUC.S-B ckt.1	400															340	85	339	84.8
	TR 400/220 kV BUC.S-BUC.S-B ckt.2	400															340	85	339	84.8
	TR 220/110 kV FUNDE2 1	200	173	86.6	168	84.1	169	84.4	193	96.7	193	96.5	200	99.9	200	99.8	209	104	208	104
	TR 220/110 kV FUNDEN 1	200							163	81.4	163	81.3	169	84.2	168	84.1	176	88	176	87.8
	TR 400/220 kV MINTIA-MINTIA B	400	386	96.4																
	TR 400/220 kV IERNUT 1	400							320	80.1			325	81.3	324	81.1				
SRB	TR 400/220 kV JBGD8 1	400															338	84.5	335	83.7
	TR 220/110 kV JBGD3 1	200							167	83.4	167	83.3	171	85.6	171	85.5	197	98.6	197	98.3
	TR 220/110 kV JBGD3 2	150							126	83.7	126	83.9	130	86.5	130	86.6	135	89.7	134	89.6
	TR 220/110 kV JZREN2 2	150							124	82.4	124	82.3					122	81.3	122	81
	TR 220/110 kV JTKOSA 2	150							131	87.1			133	88.9			132	87.9		
	TR 220/110 kV JTKOSA 3	150							133	88.7			136	90.5			134	89.5		
	TR 400/220 kV JTKOSB 1	400											323	80.8						
	TR 400/220 kV JTKOSB 2	400							326	81.4			338	84.4			325	81.1		
	TR 400/220 kV JTKOSB 3	400							326	81.4			338	84.4			325	81.1		
	TR 220/110 kV JPRIS4 1	150											122	81.1						
	TR 220/110 kV JPRIS4 2	150											122	81.1						

Based on full topology and n-1 contingency analyses, some internal network reinforcements are necessary to sustain the level of demand and the proposed GTMax generation dispatch. Most of the identified critical network elements in Romania can be relieved by dispatching actions (change in network topology or generation dispatch). Re-dispatching actions, mostly in the power system of Romania (power plants DEVA 1, LOTRU CIUNGET, PORTILE 1, PAROSENI and ROVINARI) will be necessary to keep desired network security level according to the (n-1) criterion. Also, installing a new transformer unit 400/110 kV in Brasov would help resolve some critical states in the Romanian network. Upgrading the Timisoara substation to 400 kV level and supplying this area from the 400 kV network instead of 220 kV would also resolve some problems in Romanian network.

Reinforcement of the local network in vicinity of Belgrade is necessary, but as it has been stated before, this is a local distribution problem. Supplying Belgrade area must be part of more complex and thorough analyses.

The central part of the 400 kV network in Serbia is heavy loaded due to large energy transits from Romania, Bulgaria and south of Serbia (Kosovo and Metohija) to Croatia and Hungary. Strengthening of the 400 kV corridor from Romania through Serbia to Croatia (East-West), by building a new 400 kV regional transmission interconnection Timisoara-Vrsac with new substations at Timisoara, Vrsac, Drmno and Belgrade-Obrenovac could relieve this problem.

In summary, conclusions for 2010 are:

- Expected network topology is sufficient for all investigated generation and load pattern, except in South Serbia and Belgrade area;
- Building the 400 kV corridor Nis-Leskovac-Vranje-Skoplje before 2010 would resolve all insecure states identified in network of southern Serbia;
- Network reinforcement in Belgrade area is necessary;
- Level of reactive power consumption in Albania is very high comparing to the other systems and not realistic. This causes some overloads due to low voltage profile in the Albanian network;
- High loads and overloads of elements in Romania can be relieved by operational methods.

The proposed SECI network topology for 2015 generally improves network performance, especially for the Albanian and Serbian networks. Additional network reinforcements are necessary, especially in increasing transformer capacities in several substations, over which large consumption areas are supplied. In case of Romania, it is difficult to finalise exactly what reinforcements are necessary, since most of the identified insecure states can be relieved with production re-dispatch and network topology changes.

Additional new lines (Visegrad – Pljevlja, Tumbri – Banja Luka and Pecs – Sombor) that have been proposed do not resolve any of the identified insecure states, since these lines are electrically far from these critical network elements, and therefore do not have significant influence. But, they do increase transfer capabilities of interconnected network.

In summary, conclusions for 2015 are:

- New lines commissioned to come into operation between 2010 and 2015 greatly reduce regional losses, regardless of hydrology;

- The proposed SECI network topology for 2015 is sufficient for all investigated generation and load pattern, except in Belgrade area;
- Again, building of the 400 kV corridor Nis-Leskovac-Vranje-Skoplje resolves all insecure states identified in network of southern Serbia;
- Network reinforcement in east-west corridor in Serbia is necessary (this includes Belgrade area);
- Level of reactive power consumption in Albania is very high comparing to the other systems and not realistic and this causes some overloads due to low voltage profile in Albanian network;
- High loads and overloads of elements in Romania can be relieved by operational methods;
- Additional proposed interconnection lines candidates do not resolve any of the identified problems.

3.9.4.5 *Summary and Comparison of Scenario C Results*

The results of the sensitivities run in Scenario C are summarised in Table 54. All Scenario C cases assume the same rehabilitation program as proposed by the utilities. It includes a total of 11,574 MW of existing capacity to be rehabilitated between 2005 and 2020.

For the Reference Case, an additional 11,000 MW of new capacity was added, resulting in a total Net Present Value (NPV) of investment and operating costs of €34.092 billion.

By comparison, under the Forced Hydro sensitivity case, the total amount of new capacity increased to 12,996 MW (as compared to 11,000 MW). The NPV however increased only by 1.1% to €34.464 billion. This can be also compared to the €35.904 billion NPV of the High Gas Price (using double the gas price of the Reference Case).

For the low and high demand forecast, the addition of new capacity range from 6,176 MW to 17, 632 MW, as compared to 11,000 MW for the medium load forecast. The NPV would vary from €29.5 to €37.6 billion.

The NPV of the full rehabilitation case shows an increase of €653 million, as compared to the Reference Case.

Under the Imports/Exports case, a net import of 1,500 MW base-load was assumed. To run this case, the WASP model deducted 1,500 MW of base-load demand in each hour over the period 2010-2020. As a result, the requirement for new capacity decreases to 9,220 MW and the NPV decreased to €32.423 billion. Assuming an average purchase price of €35/MWh, the NPV of the 2010-2020 purchase of 1,500 MW would be €2.040 billion. The total NPV of this Net Imports is €34.463 billion, i.e greater than the €34.092 billion of the Reference Case. The breakeven purchase price is €29/MWh.

Bringing the Belene nuclear plant on-line in 2012 instead of 2017 (in the Reference Case) increases the NPV by only €26 million.

An increase of 15% in construction costs increases the NPV by €372 million over the 2005-2020 period.

Table 54: Summary and Comparison of Scenario C Results

	Load Forecast	Gas Price Forecast	Rehab Plan	"Forced" Hydro	Rehabilitation (MW)	New Capacity (MW)	Net Present Value (Million Euros)
Reference Case	Medium	Medium	Utility	NO	11,574	11,000	34,092
Forced Hydro	Medium	Medium	Utility	YES	11,574	12,996	34,464
High Demand	High	Medium	Utility	YES	11,574	17,632	37,564
Low Demand	Low	Medium	Utility	NO	11,574	6,176	29,506
High Gas Price	Medium	High	Utility	YES	11,574	12,514	35,904
Imports/Exports	Medium	Medium	Utility	NO	11,574	9,220	32,423
Full Rehab	Medium	Medium	Utility + Full Rehab	NO	11,574	11,000	34,745
Nuclear	Medium	Medium	Utility	NO	11,574	11,000	34,118
Increase Construction Cost	Medium	Medium	Utility	NO	11,574	11,000	34,465
Discount Rate	Medium	Medium	Utility	NO	11,574	10,986	39,841

Table 55 summarises the generation mix for the Reference Case for the years 2005, 2010, 2015 and 2020. It is broken down by type of plants and between existing capacity, plants being rehabilitated, and new capacity.

Table 55: Generation Mix for Reference Case

	Existing	Rehabilitation	New Capacity	Total
		YEAR 2005		
Hydro	15,964	-	-	15,964
Pumped Storage	2,289	-	-	2,289
Oil/Gas	4,527	-	-	4,527
Coal	3,679	-	-	3,679
Lignite	12,837	-	-	12,837
Nuclear	3,520	-	-	3,520
Total	**42,816**	**-**	**-**	**42,816**
		YEAR 2010		
Hydro	15,964	-	-	15,964
Pumped Storage	2,289	-	-	2,289
Oil/Gas	3,160	519	532	4,211
Coal	2,164	1,144	-	3,308
Lignite	6,303	4,590	1,320	12,213
Nuclear	2,774	-	664	3,438
Total	**32,654**	**6,253**	**2,516**	**41,423**
		YEAR 2015		
Hydro	15,964	-	-	15,964
Pumped Storage	2,289	-	-	2,289
Oil/Gas	1,977	900	1,760	4,637
Coal	973	2,615	-	3,588
Lignite	4,027	7,005	2,814	13,846
Nuclear	2,774	-	1,328	4,102
Total	**28,004**	**10,520**	**5,902**	**44,426**
		YEAR 2020		
Hydro	15,964	-	-	15,964
Pumped Storage	2,289	-	-	2,289
Oil/Gas	1,513	900	3,756	6,169
Coal	973	2,615	-	3,588
Lignite	3,040	8,059	4,986	16,085
Nuclear	2,774	-	2,258	5,032
Total	**26,553**	**11,574**	**11,000**	**49,127**

Figure 9 shows the results in a graphical form for the total capacity in each of these selected years.

Figure 10 shows the total installed capacity (existing, rehab and new capacity) over time versus the annual demand.

By 2010, 2,516 MW of new capacity will be required in the regional system. About half would be from lignite-fired generation with the remaining 21% from gas-fired and 26% from nuclear. In 2020, the regional system would require a total amount of 11,000 MW of new capacity, with 45% from lignite-fired generation, 34% from gas-fired and 20% from nuclear

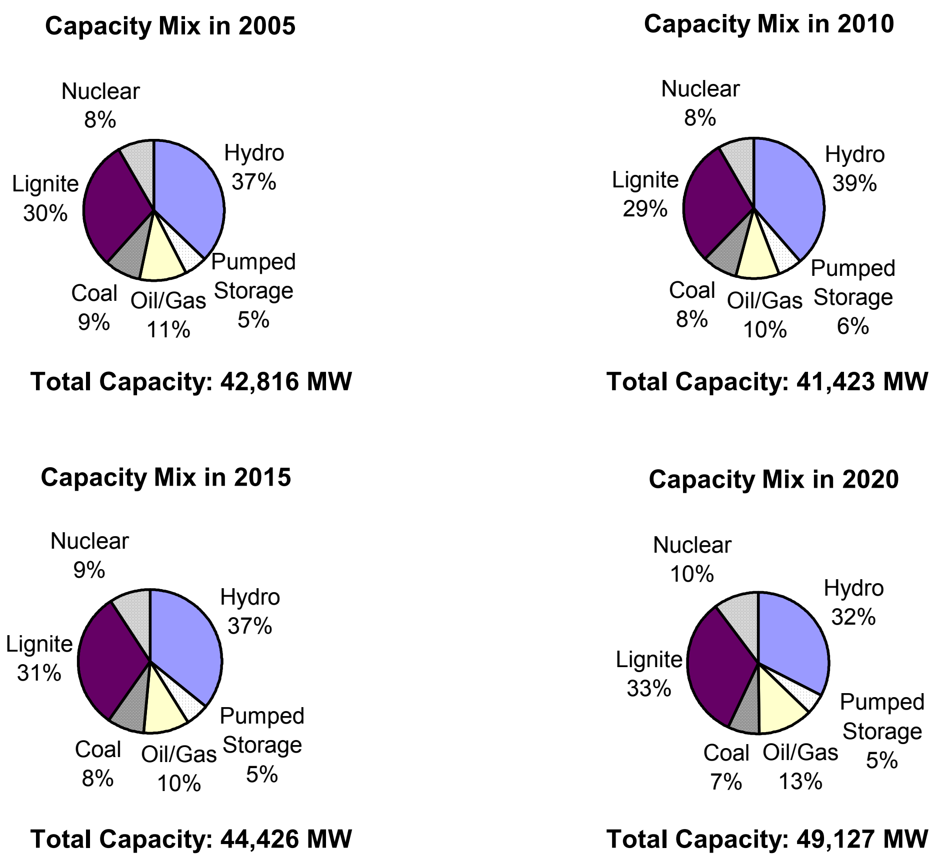


Figure 9: Reference Case Total Capacity Mix

Figure 10: Scenario C Reference Case Breakdown of Existing Capacity, Rehab, and New Generation Versus Demand

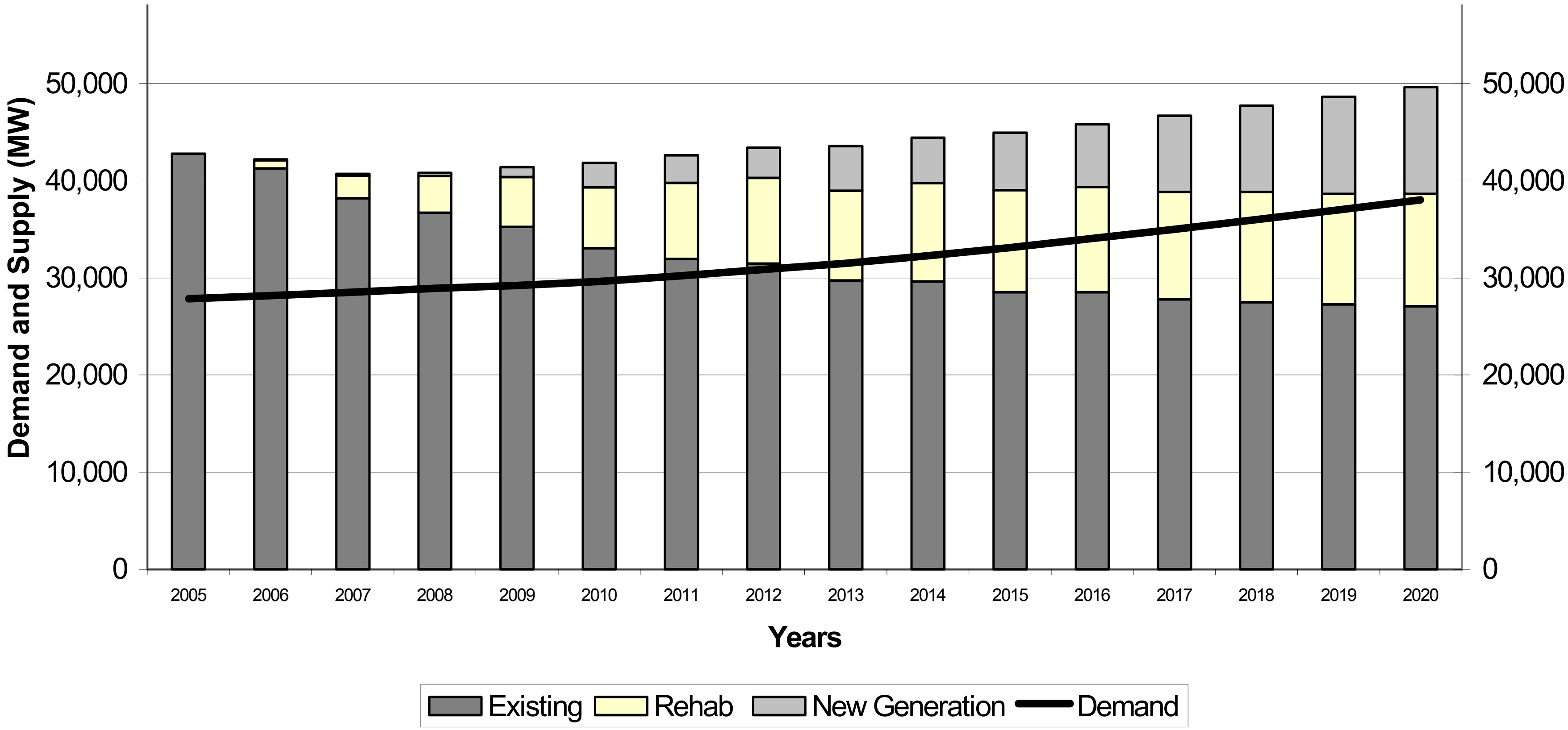


Figure 11 through Figure 15 show the capacity mix for the sensitivity cases.

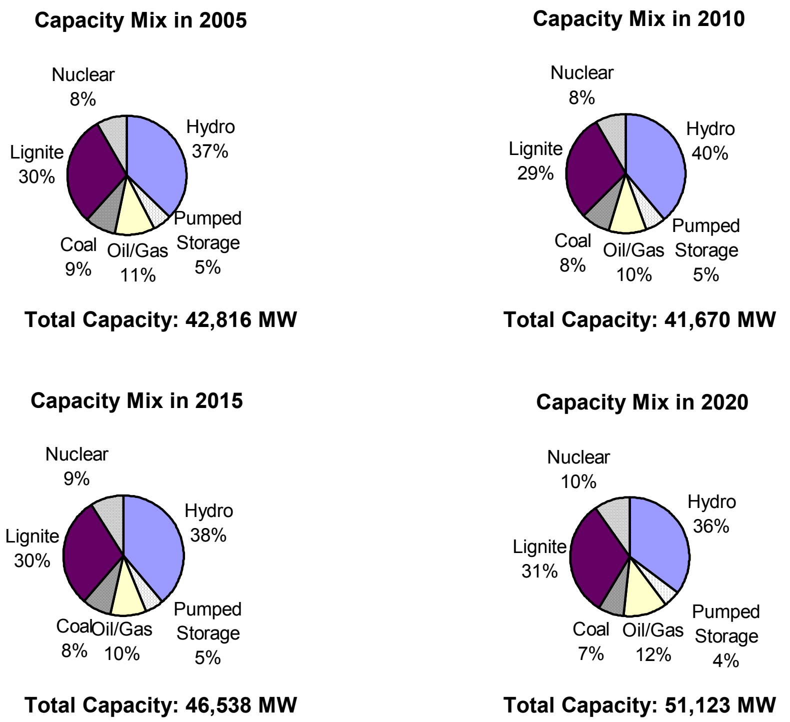


Figure 11: Forced Hydro Sensitivity Case – Capacity Mix

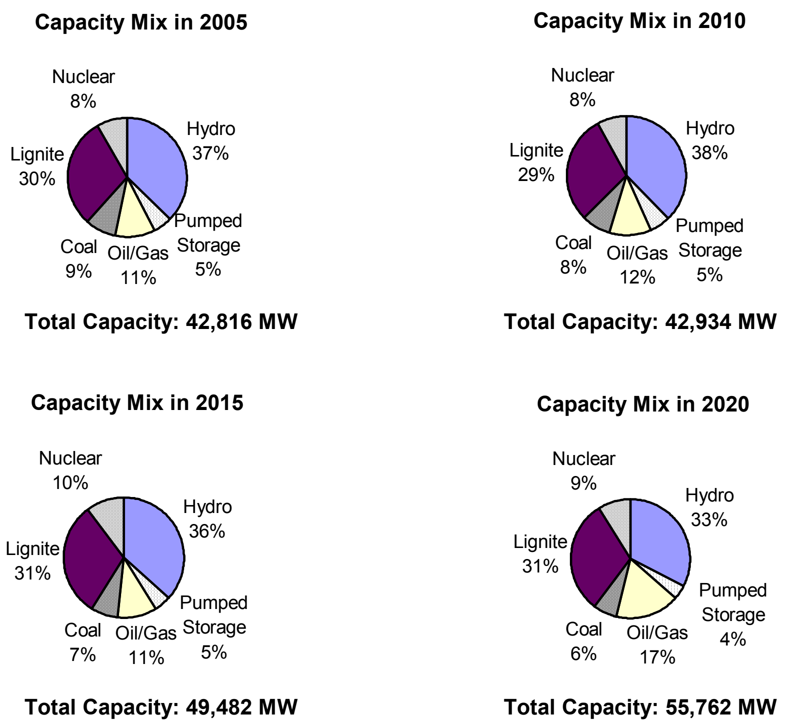


Figure 12: High Load Demand Sensitivity Case – Capacity Mix

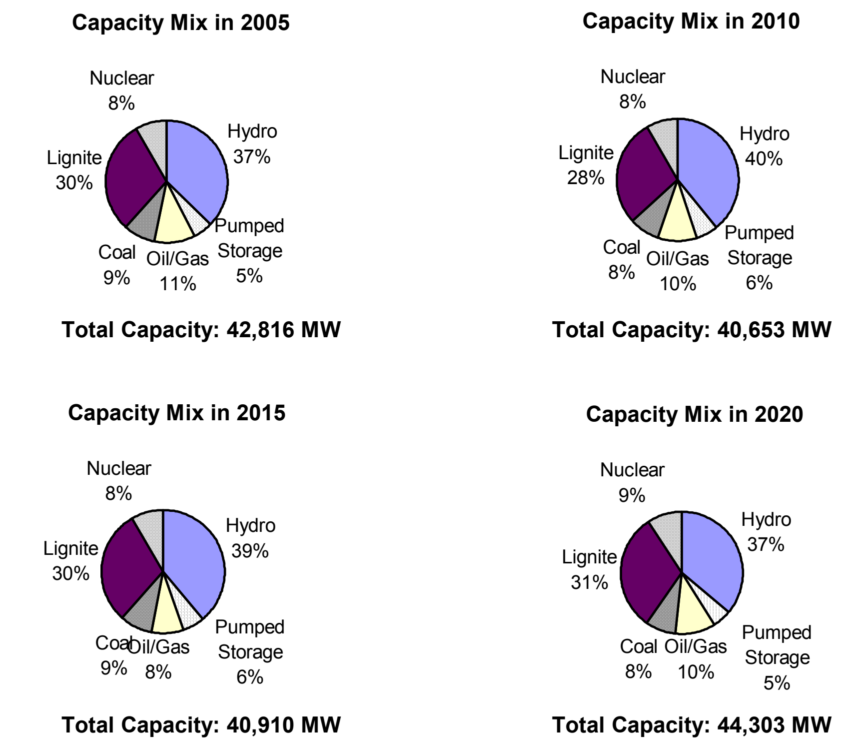


Figure 13: Low Load Demand Sensitivity Case – Capacity Mix

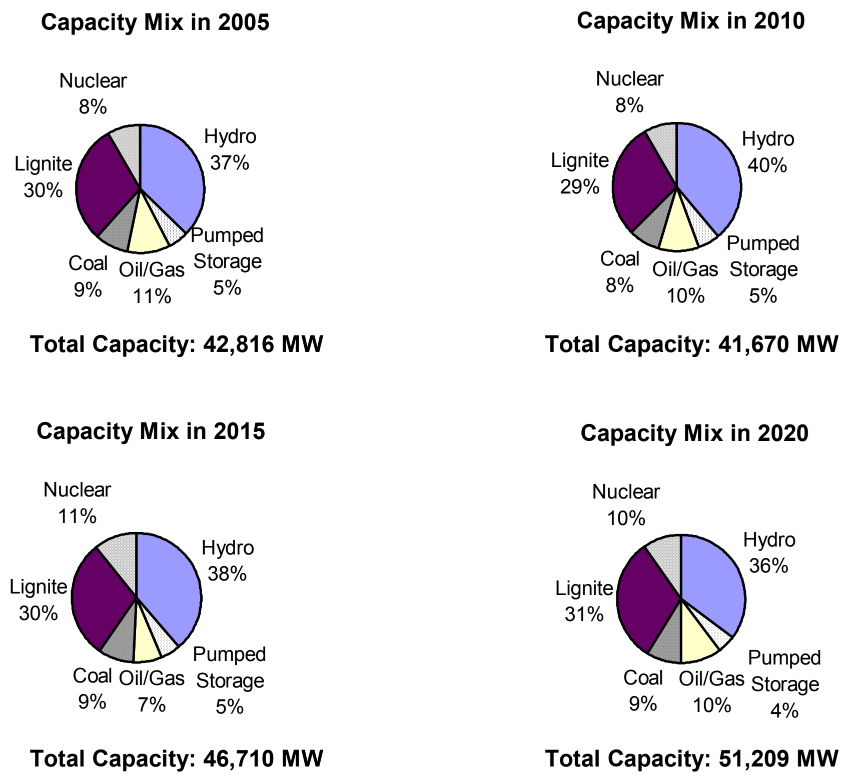


Figure 14: High Gas Price Sensitivity Case – Capacity Mix

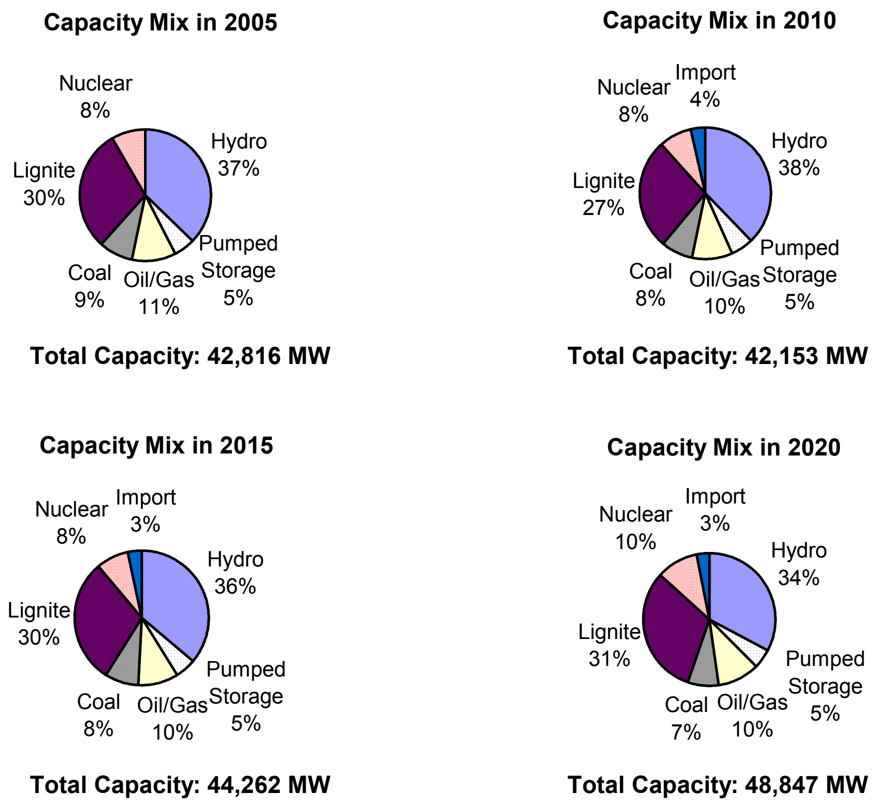


Figure 15: Import/Export Sensitivity Case – Capacity Mix

For the Reference Case, non-discounted annual construction costs for the units under life extension and rehabilitation as well as for new capacity are summarised in Table 56. Details are given in Table 57 and Table 58.

The average annual construction cost for rehabilitation is about €665 million for the period 2005-2011. It then decreases to about €232 million annually for the period 2012-2015.

For new capacity, annual construction costs quickly increase to €733 million by 2008. Until 2018, annual construction costs fluctuate between €504 million in 2012 and €929 million in 2017.

Table 56: Non-Discounted Construction Costs for Reference Case (€ million – 2005 Price Level)

Year	Life extension and Rehabilitation	New Capacity	Total
2005	491.1	171.9	663.0
2006	695.0	398.5	1,093.5
2007	783.7	679.0	1,462.7
2008	694.4	733.1	1,427.5
2009	820.2	517.2	1,337.4
2010	671.5	686.6	1,358.1
2011	499.3	871.5	1,370.8
2012	178.2	504.1	682.3
2013	415.3	637.5	1,052.8
2014	156.2	780.5	936.7
2015	178.2	781.4	959.6
2016	48.0	884.1	932.1
2017	130.2	929.2	1,059.4
2018	0.0	709.8	709.8
2019	99.1	239.3	338.4
2020	0.0	0.0	0.0
Total	5,860.3	9523.7	15,384.1

Table 57: Non-Discounted Annual Construction Costs for Life Extension and Rehabilitation (2005 Price Level)

Jurisdiction	TPP Unit Name	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Albania	TPP Fier Czech	10.3	10.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.5
	TPP Fier China	5.5	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
	Subtotal	***15.8***	***15.8***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***31.5***
B&H	Gacko	-	-	-	121.6	-	-	-	-	-	-	-	-	-	-	-	-	121.6
	Ugljevik	-	-	-	-	-	119.4	-	-	-	-	-	-	-	-	-	-	119.4
	Tuzla 5	41.1	41.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82.3
	Tuzla 6	-	43.1	43.1	-	-	-	-	-	-	-	-	-	-	-	-	-	86.3
	Kakanj 6	-	-	40.9	-	-	-	-	-	-	-	-	-	-	-	-	-	40.9
	Subtotal	***41.1***	***84.3***	***84.0***	***121.6***	***0.0***	***119.4***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***450.5***
Bulgaria	TPP Maritsa East 3 Unit 1	-	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 3 Unit 2	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 3 Unit 3	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 3 Unit 4	-	-	116.2	-	-	-	-	-	-	-	-	-	-	-	-	-	116.2
	TPP Maritsa East 2 Unit 1	77.0	-	-	-	-	-	-	-	-	-	-	-		-	-	-	77.0
	TPP Maritsa East 2 Unit 2	-	77.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 3	-	-	77.0	-	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 4	-	-	-	77.0	-	-	-	-	-	-	-	-	-	-	-	-	77.0
	TPP Maritsa East 2 Unit 5	-	-	-	-	119.5	-	-	-	-	-	-	-	-	-	-	-	119.5
	TPP Maritsa East 2 Unit 6	-	-	-	119.5	-	-	-	-	-	-	-	-	-	-	-	-	119.5
	TPP Bobov Dol 1	-	-	-	-	110.5	-	-	-	-	-	-	-	-	-	-	-	110.5
	TPP Bobov Dol 2	-	-	-	-	-	110.5	-	-	-	-	-	-	-	-	-	-	110.5
	TPP Bobov Dol 3	-	-	-	-	-	-	110.5	-	-	-	-	-	-	-	-	-	110.5
	TPP Varna 1	-	-	-	-	108.2	-	-	-	-	-	-	-	-	-	-	-	108.2
	TPP Varna 2	-	-	-	-	-	111.8	-	-	-	-	-	-	-	-	-	-	111.8
	TPP Varna 3	-	-	-	-	-	-	111.8	-	-	-	-	-	-	-	-	-	111.8
	TPP Varna 4	-	-	-	-	-	-	-	109.3	-	-	-	-	-	-	-	-	109.3
	TPP Varna 5	-	-	-	-	-	-	-	-	108.2	-	-	-	-	-	-	-	108.2
	TPP Varna 6	-	-	-	-	-	-	-	-	-	108.2	-	-	-	-	-	-	108.2
	TPP Ruse 1	-	-	-	-	17.5	-	-	-	-	-	-	-	-	-	-	-	17.5
	TPP Ruse 2	-	-	-	-	-	17.5	-	-	-	-	-	-	-	-	-	-	17.5
	TPP Ruse 3	44.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44.0
	TPP Ruse 4	-	-	-	40.0	-	-	-	-	-	-	-	-	-	-	-	-	40.0
	TPP Ruse 5	-	-	-	-	-	-	18.0	-	-	-	-	-	-	-	-	-	18.0
	TPP Ruse 6	-	-	-	-	-	-	-	18.9	-	-	-	-	-	-	-	-	18.9
	Subtotal	***353.3***	***193.2***	***193.2***	***236.5***	***355.7***	***239.7***	***240.2***	***128.2***	***108.2***	***108.2***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***2,156.3***

Non-Discounted Annual Construction Costs for Life Extension and Rehabilitation (2005 Price Level) (Continued)

Macedonia	Bitola 1		-	-	-	-	-	-	-	-	48.0	48.0	-	-	-	-	-	-	96.0
	Bitola 2		-	-	-	-	-	-	-	-	-	-	48.0	48.0	-	-	-	-	96.0
	Bitola 3		-	-	-	-	-	-	-	-	-	-	-	-	-	-	99.1	-	99.1
	Negotino		-	-	-	-	50.0	50.0	-	-	-	-	-	-	-	-	-	-	100.0
	Oslomej		-	-	-	-	-	-	25.0	25.0	-	-	-	-	-	-	-	-	50.0
		Subtotal	***0.0***	***0.0***	***0.0***	***0.0***	***50.0***	***50.0***	***25.0***	***25.0***	***48.0***	***48.0***	***48.0***	***48.0***	***0.0***	***0.0***	***99.1***	***0.0***	***441.1***
Montenegro	TPP Pljevlja		-	-	-	-	-	80.1	-	-	-	-	-	-	-	-	-	-	80.1
		Subtotal	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***80.1***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***80.1***
Romania	Turceni Unit 3		-	-	-	93.7	93.7	-	-	-	-	-	-	-	-	-	-	-	187.5
	Turceni Unit 5		22.5	22.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45.0
	Turceni Unit 6		-	-	93.7	93.7	-	-	-	-	-	-	-	-	-	-	-	-	187.5
	Rovinari Unit 3		-	82.5	82.5	-	-	-	-	-	-	-	-	-	-	-	-	-	165.0
	Rovinari Unit 5		-	-	-	-	85.2	85.2	-	-	-	-	-	-	-	-	-	-	170.5
	Isalnita Unit 7		-	-	78.3	78.3	-	-	-	-	-	-	-	-	-	-	-	-	156.6
	Paroseni Unit 4		-	-	-	70.5	-	-	-	-	-	-	-	-	-	-	-	-	70.5
	Galati Unit 3		-	-	25.0	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0
	Galati Unit 5		-	-	-	-	-	-	-	25.0	-	-	-	-	-	-	-	-	25.0
	Galati Unit 6		-	-	-	-	-	-	-	-	25.0	-	-	-	-	-	-	-	25.0
	Galati Unit 4		-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	-	15.0
	Deva Unit 1		-	123.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	123.6
	Deva Unit 2		-	-	123.6	-	-	-	-	-	-	-	-	-	-	-	-	-	123.6
	Deva Unit 4		-	-	-	-	123.6	-	-	-	-	-	-	-	-	-	-	-	123.6
		Subtotal	***22.5***	***228.5***	***403.1***	***336.2***	***317.5***	***85.2***	***-***	***25.0***	***25.0***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***1,443.1***
Serbia	Nikola TeslaA1		-	-	-	-	97.0	-	-	-	-	-	-	-	-	-	-	-	97.0
	Nikola TeslaA2		-	-	-	-	-	97.0	-	-	-	-	-	-	-	-	-	-	97.0
	Nikola TeslaA4		-	103.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	103.4
	Nikola TeslaA6		-	-	103.4	-	-	-	-	-	-	-	-	-	-	-	-	-	103.4
	Nikola TeslaB1		-	-	-	-	-	-	234.1	-	-	-	-	-	-	-	-	-	234.1
	Nikola TeslaB2		-	-	-	-	-	-	-	-	234.1	-	-	-	-	-	-	-	234.1
	KostolacA1		-	42.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42.2
	KostolacB1		-	-	-	-	-	-	-	-	-	-	130.2	-	-	-	-	-	130.2
	KostolacB2		-	-	-	-	-	-	-	-	-	-	-	-	130.2	-	-	-	130.2
	Novi Sad1		30.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.8
	Novi Sad2		-	27.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27.7
	Zrenjanin		27.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27.7
		Subtotal	***58.4***	***173.3***	***103.4***	***-***	***97.0***	***97.0***	***234.1***	***-***	***234.1***	***-***	***130.2***	***-***	***130.2***	***-***	***-***	***-***	***1,257.8***
		Total	**491.1**	**695.0**	**783.7**	**694.4**	**820.2**	**671.5**	**499.3**	**178.2**	**415.3**	**156.2**	**178.2**	**48.0**	**130.2**	**-**	**99.1**	**-**	**5,860.3**

Table 58: Reference Case – Non Discounted Annual Construction Costs (2005 Cost Level – Million $))

Year of commissioning	Plant Name	# of units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
2009	MEST	2	121.6	274.1	284.5	92.0	.	.	.	.	.	.	.	.	.	.	.	772.2
2010	CER2	1	21.0	87.2	196.5	203.9	65.9	.	.	.		.	.					574.5
2010	LB50	1	.	26.0	130.7	240.4	102.0	.	.	.	.	.	.	.	.	.	.	499.1
2010	KOLB	1	.	11.2	56.1	103.3	43.8	.	.	.	.	.	.	.	.	.	.	214.4
2011	KOLB	1	.	.	11.2	56.1	103.3	43.8	.	.	.	.	.	.	.	.	.	214.4
2012	CC30	1	.	.	.	.	6.3	85.9	81.7	.	.	.	.	.	.	.	.	173.9
2013	CER3	1	.	.	.	37.4	155.7	350.9	364.2	117.7	.	.	.	.	.	.	.	1,025.9
2013	CCHP	1	.	.	.	.	.	4.0	24.0	13.0	.	.	.	.	.	.	.	41.0
2013	K3B3	1	.	.	.	.	14.2	71.3	131.2	55.7	.	.	.	.	.	.	.	272.4
2013	LB50	1	.	.	.	.	26.0	130.7	240.4	102.0	.	.	.	.	.	.	.	499.1
2014	CCHP	1	.	.	.	.	.	.	4.0	24.0	13.0	.	.	.	.	.	.	41.0
2015	CC30	1	.	.	.	.	.	.	.	6.3	85.9	81.7	.	.	.	.	.	173.9
2015	CC50	1	.	.	.	.	.	.	.	23.7	141.2	76.1	.	.	.	.	.	241.0
2015	LB50	1	.	.	.	.	.	.	26.0	130.7	240.4	102.0	.	.	.	.	.	499.1
2016	CCHP	1	.	.	.	.	.	.	.	.	4.0	24.0	13.0	.	.	.	.	41.0
2016	CC50	1	.	.	.	.	.	.	.	.	23.7	141.2	76.1	.	.	.	.	241.0
2017	BELE	1	.	.	.	.	.	.	.	31.1	129.3	291.5	302.6	97.8	.	.	.	852.3
2017	CC50	1	.	.	.	.	.	.	.	.	.	23.7	141.2	76.1	.	.	.	241.0
2018	CC30	1	.	.	.	.	.	.	.	.	.	.	6.3	85.9	81.7	.	.	173.9
2018	K3B3	1	.	.	.	.	.	.	.	.	.	14.2	71.3	131.2	55.7	.	.	272.4
2018	LB50	1	.	.	.	.	.	.	.	.	.	26.0	130.7	240.4	102.0	.	.	499.1
2019	CCHP	1	.	.	.	.	.	.	.	.	.	.	.	4.0	24.0	13.0	.	41.0
2019	CC30	1	.	.	.	.	.	.	.	.	.	.	.	6.3	85.9	81.7	.	173.9
2019	K3B3	1	.	.	.	.	.	.	.	.	.	.	14.2	71.3	131.2	55.7	.	272.4
2019	LB50	1	.	.	.	.	.	.	.	.	.	.	26.0	130.7	240.4	102.0	.	499.1
2020	CC30	1	.	.	.	.	.	.	.	.	.	.	.	.	6.3	85.9	81.7	173.9
2020	K3B3	1	.	.	.	.	.	.	.	.	.	.	.	14.2	71.3	131.2	55.7	272.4
2020	LB50	1	.	.	.	.	.	.	.	.	.	.	.	26.0	130.7	240.4	102.0	499.1
Total		29	171.9	398.5	679.0	733.1	517.2	686.6	871.5	504.2	637.5	780.4	781.4	883.9	929.2	709.9	239.4	9,523.7

Table 59 summarises the results for the various cases analysed under Scenario C. The construction costs for new capacity vary between a total of €5.2 billion under the low demand forecast to a high of €14.0 billion under the high load forecast. For the medium load forecast, the 2005-2020 construction costs range from a low of €8.2 billion under the Net Imports sensitivity case to a high of €11.5 billion under the high gas price sensitivity case.

Table 59: Non-Discounted Construction Costs for Scenario C Cases (€ million – 2005 Price Level)

Year	Life extension and Rehabilitation	New Capacity	Total
Reference Case	5,860	9,524	15,384
Forced Hydro	5,860	11,036	16,896
High Demand	5,860	14,022	19,882
Low Demand	5,860	5,235	11,095
High Gas Price	5,860	11,488	17,348
Imports/Exports	5,860	8,163	14,023
Full Rehab	6,486	9,524	16,010
Nuclear	5,860	9,524	15,384
Increase Construction Cost	5,860	10,952	16,812
Discount Rate	5,860	9,622	15,482

3.10 Conclusions

3.10.1 Introduction

Overall, the results of the simulations demonstrate that there are benefits in considering investments on a regional basis in SEE. The increased transmission investments to support the transfer of electricity between jurisdictions provide additional benefits from a trading perspective – thereby supporting the objectives of the Regional Electricity Market. Implementing common expansion planning and operating practices could save up to €6.7bn (constant 2005 euros) over the period 2005-2020.

The Generation Investment Study has provided a number of least cost investment plans across its various scenarios, providing an indication to Governments, utilities and investors alike of the potential generation and transmission schemes that may be suitable for more detailed investigation. The study does not identify the investments that should be made – rather it identifies investments that are cost-effective under a range of scenarios. The most attractive generating plants from a regional perspective In addition to the units under construction or committed by the utilities (Bucuresti South and West in Romania, Maritsa East 1 in Bulgaria, and Vlora in Albania) are:

- Belene and Cernavoda nuclear plant;
- Kolubara lignite plant;
- 300MW or 500MW Kosovo A lignite plant;
- generic 300MW or 500MW combined cycle plant;
- generic 100MW simple cycle plants; and
- generic 500MW super-critical imported coal plant.

Conventional hydro plant and pumped storage plant play a key role in meeting peak demand and reducing marginal prices. However, no hydro plant were selected in the reference case. The sensitivity analysis demonstrates that investment costs for hydro are high but operational costs low – raising the question of whether cost is the sole criteria for investment decisions. The potential benefit offered by hydro plant is that of fuel diversity, and protection against high gas prices.

It is important to note that the current level of reserve margins across the region as a whole is very high. This means that new capacity is not required until 2010. However, if rehabilitation were to become less economic (e.g. if environmental requirements were to become significantly more strict), this might change.

Rehabilitation is also a key part of the expansion plan. Over the study period, a total of 11.5GW is scheduled by the utilities for rehabilitation, upgrade or life extension.

Table 60 summarises construction and operating costs for both Scenarios A and C. The results show a total saving of €6.7 billion with the regional scenario over the 2005-2020 study period. To meet the same LOLP criteria, Scenario A would require a total capacity of 15,488 MW for new power plants, or an increase of 4,488 MW as compared to the regional scenario.

Table 60: Comparison of Non-Discounted Costs Between Scenarios A and C (€ billion)

	Individual Jurisdictions	Regional Scenario
Construction cost for new capacity	12.122	9.524
Construction cost of rehabilitation and life extension	5.860	5.860
Fuel costs	38.994	35.246
O&M costs	20.574	20.254
Total costs	77.550	70.886

3.10.2 Results for the Regional Sensitivity Cases

The robustness of the regional reference case is demonstrated by the results of the sensitivity cases. The range of sensitivities (rehabilitation costs, hydro commitment, high gas price, high or low demand, alternative import/export plans, full environmental compliance, and early commissioning of Belene nuclear plant) allowed the attractiveness of various candidate plant to be assessed. The financial results of the analyses are shown in Table 61.

These findings allow us to conclude that:

- Kosovo lignite plant are the most likely candidate for early development;
- hydro plant only become attractive under scenarios of high gas prices, but have non-financial benefits such as fuel diversity and reduction of peak prices;
- combined cycle plant are very competitive under the medium gas forecast but are postponed until the mid 2010s under a high gas price; and
- Imported coal plant are only attractive under high gas prices.

Table 61: Results of Sensitivity Cases (Non-discounted costs € billion)

	Reference Case	Rehab Sensitivity	Forced Hydro	High Gas Price	High Load Demand	Low Load Demand	Imports-Exports	Full Rehab	Alternative Nuclear
Construction cost for new capacity	9.524	12.501	11.036	11.488	14.022	5.234	8.163	9.524	9.524
Construction cost of rehabilitation and life extension	5.860	2.664	5.860	5.860	5.860	5.860	5.860	6.486	5.860
Fuel costs	35.246	32.181	34.503	36.628	37.969	29.592	32.092	35.187	35.104
O&M costs	20.254	20.862	20.550	20.980	22.016	18.683	19.538	20.855	20.496
Imports Purchase	0	0	0	0	0	0	4.336	0	0
Total costs	70.886	68.208	71.969	74.956	79.867	59.369	69.989	72.052	70.984

Note: Imports costs is based on a net imports of 1,500 MW base load at an average 2005 price of €30/MWh for the period 2010-2020

3.10.3 Results of the Net Present Value Analysis

A Net Present Value (NPV) was calculated for each case run under Scenarios A, B, and C. A discount rate of 10% was used to discount each of the 2005-2020 annual investment and operating costs to a 2005 reference year. Table 62 summarises the results.

Analysis of the NPVs does not distinguish between the costs of investment in new plant and the future O&M costs. For example, comparing a “forced hydro” case with the reference case results in a difference in NPV of less than €500m. This hides the fact that more new plant is required in the forced hydro case and that the savings would be made on operating costs. We consider that NPVs provide useful supplementary information at this early stage of analysis but that they should be considered alongside investment and O&M costs.

In all cases using the medium demand forecast, the NPV of the regional sensitivities is lower than that of Scenario A where analysis was based on individual jurisdictions. This supports the conclusion that the most effective investment plans will be those that are based on regional considerations.

Table 62: Summary and Comparison of Scenario C Results

Scenario	Case	Load Forecast	Gas Price Forecast	Rehab Plan	"Forced" Hydro	Rehabilitation (MW)	New Capacity (MW)	Net Present Value (Million Euros)
A	Individual Jurisdictions	Medium	Medium	Utility	NO	11,574	15,488	37,093
B	Case 1A	Medium	Medium	Utility	NO	11,574	11,000	34,092
B	Case 2A1	Medium	Medium	Utility	NO	6,105	15,202	31,894
B	Case 2A2	Medium	Medium	Utility	NO	9,916	11,884	33,761
B	Case 2B	Medium	Medium	Utility	NO	9,916	11,884	33,637
C	Reference Case	Medium	Medium	Utility	NO	11,574	11,000	34,092
C	Forced Hydro	Medium	Medium	Utility	YES	11,574	12,996	34,464
C	High Demand	High	Medium	Utility	YES	11,574	17,632	37,564
C	Low Demand	Low	Medium	Utility	NO	11,574	6,176	29,506
C	High Gas Price	Medium	High	Utility	YES	11,574	12,514	35,904
C	Imports/Exports	Medium	Medium	Utility	NO	11,574	9,220	32,423
C	Full Rehab	Medium	Medium	Utility + Full Rehab	NO	11,574	11,000	34,745
C	Nuclear	Medium	Medium	Utility	NO	11,574	11,000	34,118
C	Increase Construction	Medium	Medium	Utility	NO	11,574	11,000	34,465
C	Discount Rate	Medium	Medium	Utility	NO	11,574	10,986	39,841

3.10.4 Operating costs

Our conclusions on operating costs are based on consideration of peak week costs in 2010 and 2015 supplemented by quarterly analysis.

Table 63 summarises the operating costs (fuel and variable O&M) for each week. The importance of hydrological conditions again supports the conclusion that a regional approach to investment and electricity market operation will reduce overall investment and operating costs. Even on a regional basis, the difference in annual operating costs is marked.

Table 63: Total Operating Costs for the Regional Market Operation in 2010 and 2015

	Operating Costs Under Different Hydrological Conditions (€'000)		
	Dry	**Average**	**Wet**
Regional Market Operation in 2010			
Week 3 (January)	58,466	50,301	45,797
Week 16 (April)	40,294	33,174	30,502
Week 29 (July)	44,311	39,918	37,665
Week 42 (October)	51,079	44,627	40,594
Estimated Annual	2,523,952	2,184.264	2,009,253
Regional Market Operation in 2015			
Week 3 (January)	63,536	55,856	52,238
Week 16 (April)	47,304	40,417	37,550
Week 29 (July)	48,717	43,386	41,338
Week 42 (October)	53,873	49,960	46,590
Estimated Annual	2,774,564	2,465,048	2,310,299

Taking the analysis one step further to consideration of hourly marginal costs (MC) allows us to conclude that there will be significant variations in costs over a year, dependent on hydrological conditions (see Table 64 for summary). Again, the regional market will shield individual jurisdictions from some of the potential volatility.

The assumed construction of transmission lines over the study period means that there are no transmission constraints impacting marginal costs.

Table 64: Average MC for the Regional Market Operation in 2010 and 2015

	Weekly MC Under Different Hydrological Conditions (€/MWh)		
	Dry	**Average**	**Wet**
Regional Market Operation in 2010			
Week 3 (January)	30.9	25.9	22.8
Week 16 (April)	28.7	17.7	17.1
Week 29 (July)	31.9	28.0	27.8
Week 42 (October)	35.0	27.3	27.2
Regional Market Operation in 2015			
Week 3 (January)	27.2	22.6	22.6
Week 16 (April)	25.0	17.8	16.9
Week 29 (July)	28.2	25.5	25.3
Week 42 (October)	29.2	24.8	25.0

We have not translated these costs into marginal prices, since the analysis has not considered returns on equity investments, debt coverage or the "price" of hydro in a deregulated market. Further work would be required to assess how marginal prices might compare to marginal costs in a regional market.

3.10.5 Transmission investments

Our analysis, coupled with that of EKC using the PSS/E model, indicated that the expected network topology for 2010 would be sufficient to meet the generation and load patterns for year 2010 under the medium load forecast, except in South Serbia and Belgrade areas. Our results suggested that building the 400-kV corridor Nis-Leskovac-Vranje-Skoplje would resolve stability problems.

In addition, there are also a number of critical network elements in Romania that are overloaded. More detailed investigations and studies are required to develop solutions and, most likely, additional transformer capacity in the sub-transmission system will be required.

The level of reactive power consumption in Albania is also very high and needs to be addressed.

For 2015, the proposed additional transmission lines would reduce losses in the region and allow normal operation of the regional network.

The proposed addition of 1,800 MW of lignite in UNMIK by 2015 and additional capacity in the future will have an impact on the internal network of UNMIK and its surrounding power systems. More detailed analyses of these impacts are required. One possible solution would be to build a 400-kV ring to connect new production facilities to the existing substation at Kosovo B and the new one at Pristina 4.

A total of 7 new regional transmission lines have been proposed by the South East Europe Cooperative Initiative (SECI) for operation by 2010. The expected total construction cost of these lines together with the associated substations is €241m. By 2015, an additional €100m has been proposed for 3 new transmission lines.

(Zemlak-Bitola, Kashhar-Kosovo B and Skopje-Vranje-Nis) and associated substations. These investments do not include the need for continued expansion and upgrade of the local sub-transmission and distribution networks, nor reinforcement of the east-west corridor in Serbia and critical transmission network elements in Romania.

Based on the preliminary analyses performed under the GIS study, recommendations for additional investments are presented in Table 65 and Table 66. These recommendations should be taken into consideration in future studies and analyses. The total construction cost of these lines would be about €72 million and €24 million for the transformers.

Table 65: Recommendation for new transmission lines

Country	Line	Voltage	Length (km)
Romania	Arad-Timisoara	400 kV	55
Serbia	Obrenovac-Belgrade ?-Pancevo	400 kV	80
	Drmno-Vrsac	400 kV	50
UNMIK	TPP Kosovo NEW-Pristina	400 kV	20
	TPP Kosovo NEW-Kosovo B	400 kV	20
Interconnection	Timisoara (ROM)-Vrsac (SCG)	400 kV	80

Table 66: Recommendation for new transformers in new substations

Country	Name of substation	Voltage levels kV/kV	New transformers MVA
Romania	Timisoara	400/110	2x300
Serbia	Vrsac	400/110	2x300
	Beograd ?	400/110	2x300
UNMIK	Pristina	400/110	2x300

It should be noted that the GIS did not include an analysis of all the needs for reinforcement, upgrade and expansion of major transmission lines and substations within each jurisdiction. Neither did it address investment needs at distribution levels. Over the next 10 years, it is likely that the total required investments would be greater than those discussed above, which only relate to the operation of a regional electricity system.

Similarly, no analysis was performed for the transmission and distribution needs under Scenario A (individual jurisdictions). However, it is clear that the greater number of new plant identified for investment under Scenario A would all require transmission links to load centres, which would, in turn, lead to increased investments in transmission and distribution. Additional investments would also be required in each jurisdiction to meet the same n-1 network reliability criteria.

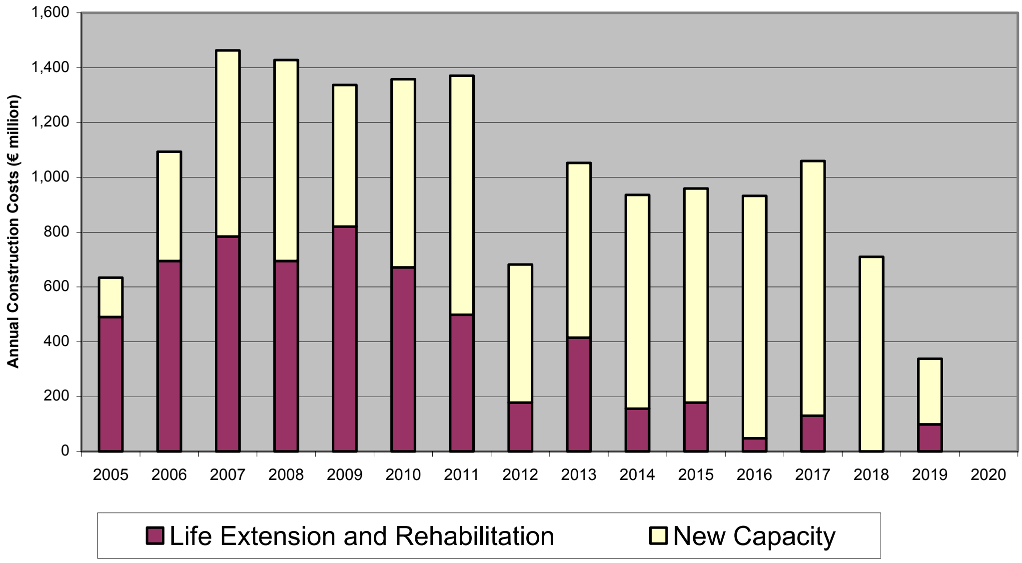
3.10.6 Annual Investment requirements

We have highlighted the total investment needs under the reference case and scenario A (Table 60). Figure 16 illustrates the annual split of the €15bn requirements for Scenario C reference case. As expected, the balance between investment on rehabilitation and life extension is highest in the earlier part of the study period, whilst the investment in new capacity represents a higher proportion over time.

The emphasis on rehabilitation in the short to medium term supports the conclusion that, given new capacity already planned, additional new capacity is not required from a security of supply margin perspective until around 2010. The rehabilitation and life extension appears a cost-effective means of dealing with the power shortages, although we recommend that projects hare studied in more detail to check the robustness of their viability.

It should be noted that our study does not conclude that no further investments are required after 2018. A longer modelling period would be required to assess investments after year 2018.

Figure 16: Annual Non-Discounted Construction Costs



3.11 Recommendations

This section highlights a number of specific points that should be taken into account over the next two years, as the conclusions and recommendations of this study are put into effect.

3.11.1 Continued review of regional development plans

- We believe that the regional development plans outlined in this study should be reviewed and revised on a two-yearly cycle. Any revision should take account of the actions that have been taken in the intervening period (e.g. detailed feasibility studies for new and plant planned for rehabilitation, project contracts, new candidate projects where appropriate).

- The demand forecast should be also updated on a two-yearly cycle, recognising that it will be less detailed than forecasts undertaken for specific jurisdictions. Where more detailed studies have been undertaken, the results should be provided for comparison purposes.

- An inventory of regional projects and supporting data should be maintained, together with the necessary information to include them as candidate projects. This inventory should be updated with additional information on projects as more detailed data become available. This is a task that might be facilitated by a regional group similar to the SECI group. The SEETEC-GIS databases of existing and proposed power plant and jurisdiction-specific fuel prices could form a major input into this inventory, and would greatly ease the process of updating data for simulation purposes.

3.11.2 Establish regional policy frameworks for investment consistent with the REM

- Establish adequacy targets for the SEE region and define a process by which utilisation of existing transmission capacity can be improved, within current regional initiatives and the development of the REM.

- The donors (and their consultants) should continue to work with the regional transmission group (SETSO) to ensure that any transmission issues that might impact updates of the investment plan are identified in advance, providing full coordination and harmonization of generating and transmission network systems development at the SEE regional level.

3.11.3 Monitor key indicators that could signal changes in regional plans

- As part of the review and updating of the investment plan, report on the regional load-resource situation to identify if the investment process needs to be slowed or accelerated.
- Monitor environmental compliance and the costs of compliance to identify whether the assumptions on refurbishment of plant remain valid as abatement techniques improve.

3.11.4 Assess the impact on transmission networks of the regional capacity expansion plans

- More detailed investigations and transmission network system operating studies should be undertaken to determine the extent to which the proposed 2010 regional transmission network system would be strengthened by development of the Nis-Vranje-Skopje 400kV corridor and the Romanian network strengthening identified in the main report.
- The long-term impact of significant new generation within the local networks and surrounding power systems should be assessed on a regular basis.
- Regular analyses of regional generation dispatch cases to monitor the demand/supply balance.

3.11.5 Short-term Priority Action Plans

We have identified a number of short-term actions that would support the developments discussed above:

- Initiate feasibility studies of projects that have been identified as near-term capacity. In particular, this should include the feasibility of new lignite capacity in UNMIK.
- Further, more detailed, investigations into the transmission requirements for the region in the medium term should be undertaken.
- Current plans for rehabilitation across the region should be reviewed, based on EC environmental requirements and economics of new regional capacity, with a view to determining a regional framework for environmental rehabilitation.
- The significant impact of future gas prices on the expansion plan means that a more detailed study on the plans for regional gas supply and distribution, together with a more comprehensive view on pricing, would be valuable.

The actions that the region takes now and over the next two to three years will determine the success of the SEE power system investment plan.

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