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Form 1.2 REPORT COVER PAGE

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Abbreviations, Acronyms and Glossary

Atkins	Atkins International, a partner firm in the consortium
Beneficiary Countries	Albania, Bosnia and Herzegovina, Croatia, Serbia/Montenegro, Kosovo (pursuant to UN resolution 1244) and the former Yugoslav Republic of Macedonia
CAGR	Compound Annual Growth Rate
CARDS	Community Assistance for Reconstruction, Development and Stabilisation
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CIDA	Canadian International Development Agency
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EE	Eastern Europe
FDI	Foreign Direct Investment
GDP	Gross Domestic Product
GW	Giga Watt
GWh	Giga Watt hour
GIS	Generation Investment Study
IFI	International Funding Institution
MWH	Montgomery Watson Harza, a sub contractor to the PwC Consortium
MWh	Mega Watt hour
MW	Mega Watt
PwC	PricewaterhouseCoopers LLP, the firm leading the Consortium
PwC Consortium	The PwC/CMcK/Atkins Consortium, led by PwC, that has been awarded the contract to implement the project
REM	Regional Electricity Market
SECI	South East Europe Cooperative Initiative
SEE	South East Europe
SEEC	South East Europe Consultants Ltd, a sub-contractor to MWH
UCTE	Union for the Co-ordination of Transmission of Electricity
UN	United Nations
UNMIK	United Nations Mission in Kosovo
USAID	US Agency for International Development
WASP	Wien Applied System Planning (Generation Expansion plan modelling tool)
WB	World Bank

1 Executive summary

1.1 Objectives

The GIS Final Report documents the work undertaken for the Generation Investment Study, within the wider Regional Balkans Infrastructure Study. Its main objective is to assist the European Community (EC), IFIs and donor bodies in identifying an indicative priority list of investments in power generation and related electricity infrastructure from a regional perspective; i.e. in line with the objectives of the regional electricity market in South East Europe (SEE). The study commenced in late 2003, has been financed by the EC and project-managed by the WB.

The specific objectives of the GIS can be summarised as follows:

- Create a medium to long term investment plan for the priority projects in electricity infrastructure, suitable for international financing;

- Recommend a methodology and proper procedures to monitor the implementation of the above investment plan;

- Determine the optimal timing, size and location of future generating capacity in the region over the period 2005 – 2020; and

- Identify priority investments in main transmission interconnection lines between the countries and sub-regions to help optimise investment requirements in power generation over the study horizon.

The three outputs arising from the study cover both demand and generation:

- A comprehensive demand forecast, which takes account of the impact of reform, recent projections and the uncertainty associated with economic growth in the region;

- An indicative least-cost generation expansion plan for the region which balances the needs for economic development and environmental protection together with the requirements related to the establishment of a regional electricity market and EU accession; and

- Evaluation of a number of alternative scenarios to establish the robustness of the least-cost plan.

A complementary study funded by the World Bank was performed to analyse the environmental impacts of the recommended expansion plans, the SEEC Study, "Implications for Investments in Environmental Protection". The results presented here should be considered in conjunction with the findings of that study.

1.2 Overview of the study

The GIS brings together both the demand and the supply side of the electricity sector. It combines demand forecasting with least cost investment planning, assessing whether incremental demand should be met through rehabilitation or the addition of new generation and/or regional transmission capacity. Such investment decisions are based on fuel, operating and capital costs. The study considers 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 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; and

- The third scenario (Scenario C) is based on a detailed hourly market simulation for two years (2010 and 2015), and models the actual operating conditions in the REM based on the candidate capacity projects identified as regional priorities in scenario B, 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.

The robustness of the results was assessed through sensitivity analysis, focusing in particular on:

- The cost of rehabilitation;

- Higher gas prices;

- A lower discount rate;

- An alternative assumption on the timescales for the entry into service of Belene nuclear power station;

- An alternative view on the imports and exports into and out of the region; and

- Alternative demand levels and hydrological conditions.

1.3 Approach to the work

The work has been consultative and iterative in nature. Data requirements have been sourced from other studies undertaken in the region, utilities, regulators and governments, and amendments made by the team to ensure consistency across jurisdictions. Two workshops have been held to discuss interim results and to highlight areas where further discussions were required. A third presentation provided an update on progress. The team recognises that power systems planning is not an exact science and has focused on the robustness of results across alternative scenarios and consistency with other studies.

1.4 Demand forecasts

The forecast demand for electricity is a key driver in planning the amount of generation capacity that may be required by an electricity system in the future. In order to determine a least cost investment plan for each of the nine countries in the study, it was necessary for us to developed a single demand forecasting technique which we applied, following the same methodology, to each of the jurisdictions in SEE.

The model developed to forecast the SEE electricity demand to 2020 adopts a top-down approach, which assesses electricity demand based on an analysis of key macro level drivers. This approach was selected because of the absence of a consistent set of economic data required for a full bottom-up approach across the region. The top-down approach has been applied with minor modifications to all jurisdictions and takes into account the effects of macroeconomic transition and post-conflict recovery in the region.

The key macroeconomic measure used in the model is electricity intensity, defined as the amount of electricity per unit of economic output, measured as the Gross Domestic Product. In SEE, this measure is high compared with a range of CEE and EC countries; as development takes place, there is an expectation that electricity intensity will decrease. The model combines future GDP forecasts with an expected electricity intensity adjustment forecast to derive future electricity demand forecasts. Some of the key assumptions made in our demand forecast include:

- A linear relationship between the growth of new electricity demand and economic growth;

- A more complex relationship between existing electricity demand and economic growth (i.e. electricity intensity). The electricity intensities in some Eastern European countries have fallen sharply as the economy diversified away from energy intensive industries or invested in equipment or processes to improve electricity intensity. This process is expected to happen in SEE over the period of the demand forecast;

- In broad terms, SEE jurisdictions' economic growth will remain at levels higher than the 2-3% likely for EC countries, as these economies converge on the average EC levels of economic output in the long term. This infers average economic growth rates of 3-5% in SEE; and

- If, due to specific social or economic conditions, electricity intensities remain high in some jurisdictions, those economies will become less competitive and growth of both economies and new electricity demand will be constrained.

To address the uncertainty in the demand forecasts, we have derived three alternative scenarios. Table 1 shows the range of demand growth forecast under the three scenarios:

- The central case forecasts a +2.3% regional electricity demand average growth to 2020;

- The low case forecasts a +1.3% average growth and the high case a +3.1% average growth to 2020; and

- There is significant variation between jurisdictions; the lowest average growth is –1.3% and the highest is +4.9%.

Table 1: SEE Electricity demand forecasts CAGR 2003-2020

	Compound annual growth value in gross electricity demand 2003-2020		
	Case 1	Case 2	Case 3
Albania	2.0%	4.0%	4.9%
Bosnia and Herzegovina	2.3%	3.0%	3.4%
Bulgaria	0.8%	1.6%	2.5%
Croatia	2.5%	3.2%	3.9%
UNMIK	1.7%	3.2%	4.3%
FYR Macedonia	1.5%	2.5%	3.0%
Montenegro	-1.3%	0.7%	1.2%
Romania	1.2%	2.6%	3.6%
Serbia (excluding UNMIK)	1.1%	1.1%	1.6%
SEE	1.3%	2.3%	3.1%

The three demand forecasts shown in Table 2 demonstrate the impact of these forecast growth rates on electricity demand. They capture a wide range of possible paths; the impact on regional demand in Case 1 is -15% below the central case, and +14% above in Case 3. There is significant difference among the jurisdictions; the largest decrease in Case 1 from the central case is -30% while the largest increase in Case 3 from the central case is +20%.

Table 2: SEE forecast electricity demand, 2020

	Gross electricity demand 2020 (GWh)		
	Case 1	**Case 2**	**Case 3**
Albania	8,964	12,490	14,530
Bosnia and Herzegovina	14,431	16,404	17,506
Bulgaria	37,000	42,481	49,278
Croatia	23,086	25,889	29,010
UNMIK	6,118	7,800	9,375
FYR Macedonia	9,378	10,965	11,857
Montenegro	3,367	4,820	5,231
Romania	60,938	76,796	91,397
Serbia (excluding UNMIK)	37,556	37,556	40,574
SEE	200,839	235,201	268,758

In order to capture the possible impact on the SEE region of sharing hydroelectric resources, as well as exploiting temperature and peak demand timing differentials through the efficient use of the transmission system, we have forecast hourly electricity demand for specific weeks, and annual maximum and minimum days of the forecast period in each jurisdiction. We have incorporated a number of assumptions in our daily demand profiles concerning the evolution of hourly demand in future. Chief among these assumptions is the flattening of the seasonal, monthly and daily variation in demand. Our forecasts assume that, in the long term, the move to more cost-reflective pricing in electricity markets will send effective price signals to consumers to enable them to smooth their demand profiles and maximise the efficiency and running of the electricity system.

In addition, we have factored in the possibility of continued growth in demand in summer months from increased air conditioning demand and decreased demand in winter due to a move to more efficient heating systems in homes and businesses. We have modified assumptions to take account of local conditions such as the existing level of gas and substitute fuel penetration, and social and political barriers to changes in pricing and usage trends.

Our forecasts have been discussed with project sponsors and senior government, utility and regulatory representatives in each jurisdiction. The forecasts reflect a plausible range of scenarios that reflect the economic, political and social realities in those jurisdictions. We have compared our forecasts with other demand forecasts for jurisdictions in the region and analysed any differences. Our methodology has been subject to peer review, which concluded that our forecasts are suitable for the purpose of this study.

A key point relating to the context in which our demand forecasts should be used is that we have considered the SEE jurisdictions as a group that will develop broadly in step with each other, whilst proceeding on a growth path toward European integration. Consequently, the implied growth and demand evolution in these jurisdictions has been considered in terms of the development of the region as a whole. The regional demand forecast provides an input into the generation and transmission modelling simulations, which in turn, focus on investments from a regional perspective.

1.5 Fuel costs

Our assumptions on fuel costs and their development over time are derived from discussions with the utilities and the knowledge of the Consortium. We consider the influences of a variety of factors on fuel costs, including:

- Differentiation between local and imported fuels;
- Fuel substitution; and
- Timescales for infrastructure implementation to allow for the introduction of new fuel services to individual jurisdictions.

For each jurisdiction, we consider only those fuel types that might realistically be used for generation. For example:

- Lignite rather than imported coal is assumed for UNMIK;
- Albania is assumed to have no access to gas until 2010.

One particular area of focus is the price of gas. We consider a base price of €105/TCM and a high price of €210/TCM to allow a comparison of the relative costs of gas-fired plant versus coal-fired plant or hydro plant.

1.6 Expansion planning criteria

As specified in the ToRs, the WASP and GTMax models were used to develop long-term expansion plans and to analyse hourly operation of all the individual power systems in regional scenarios. Regional transmission constraints were taken into account in the GTMax model and further tested in the PSS/E model for power flows and voltage profile analyses under normal and n-1 regional system operating conditions. The following criteria for expansion planning and economic assumptions were used:

- A planning period of 1 January 2005 to 31 December 2020;
- All costs were set to a January 2005 base price level and excluded general inflation;
- The analysis was undertaken in Euros at an exchange rate of $1 to €0.8375;
- A basic real discount rate of 10% was assumed, discounted to January 2005. A sensitivity run was performed with a reduced discount rate of 7%;
- A range of reserve margins was used for the initial WASP selection of potential expansion plans. The final selection was based on a Loss of Load Probability (LOLP) criteria of one day per annum; and
- An average economic value of 0.42€/kWh (0.50$/kWh) was used for electric energy not served.

1.7 Generating plant assumptions

During the data collection phase, a number of meetings and discussions were held with utilities and government agencies regarding the existing and future structure of each power system. Rehabilitation programmes for life extension of existing units and compliance with environmental upgrades were obtained from utilities and analysed.

A number of specific and generic candidate plant were identified to meet growing demand. The main assumptions on retirements and candidate plant are described below:

- **Nuclear**. In Bulgaria, Kozloduy units 3 and 4 are planned to be retired in December 2006, with units 5 and 6 available through 2020. Belene unit 1 was included as a candidate plant. In Romania: Cernavoda unit 1 is scheduled to be available through 2020, and units 2 and 3 were included as candidate plant. In Croatia, Krsko unit 1 is also scheduled to be available through 2020, with a 50:50 split of its output with Slovenia. No other nuclear candidates are expected in the region through 2020;
- **Thermal**. Details on actual refurbishment and/or retirement plans were obtained from the utilities. For Romania and Bulgaria, rehabilitation included life extension and full

environmental compliance (particulate, NOx and SOx controls) with EC regulations (Directive 2001/80/EC). For the other jurisdictions, rehabilitation included technical rehabilitation (life extension) but only partial environmental compliance (particulate and NOx). A sensitivity case with full compliance for all jurisdictions was performed.

All expansion plans include units under construction or committed by the utilities: Bucuresti South and West in Romania, Maritsa East 1 in Bulgaria, and Vlora in Albania.

Screening curves were used to select the most attractive candidates for new capacity. These include the proposed Belene and Cernavoda nuclear units, the Kolubara lignite plant in Serbia, new 300-MW or 500-MW Kosovo A lignite units in UNMIK, 300-MW and 500-MW generic combined cycle units, 100-MW generic simple cycle units, and 500-MW generic super-critical imported coal units;

- **Combined Heat and Power.** Unless specified by the utilities, existing CHP plant are assumed to continue in operation through to 2020. New 100-MW CHP units were also considered as candidates; and

- **Hydro and Renewable.** All existing hydro plant are expected to continue operation through to 2020 under current operating policies, unless specific rehabilitation and upgrade plans were provided by the utilities. New hydro candidates from identified sites specified by the utilities were investigated. Other renewables are considered to have a small impact on future generation.

1.8 Imports and exports assumptions

- Currently, power imports and exports within the SEE region and with surrounding jurisdictions are based on short-term transactions and not on long-term agreements, except for a few cases of sharing power plant between jurisdictions. Historical import/export data show great variations from year to year.

- The impact of the reconnection of UCTE 1 and 2 has increased the potential for major power transactions, but there is no indication at this time of the timing and magnitude of these transactions. We have not evaluated 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 were considered in the Base Case assumptions. A sensitivity case was made assuming a net import of 1,500 MW of base load into the SEE region, for 2010-2020.

1.9 Transmission assumptions

A series of discussions were held with the South East Europe Cooperative Initiative (SECI) group to define the regional transmission network system topology for 2010 and 2015. The regional transmission interconnection lines planned to be in operation by 2010 are:

- Ugljevik – S. Mitrovica (between Bosnia & Herzegovina and Serbia);

- Kashar – Podgorica (between Albania and Montenegro);

- Maritsa Istok – Filipi (between Bulgaria and Greece);
- C. Mogila – Stip (between Bulgaria and FYR Macedonia);
- Ernestinovo – Pecs (between Hungary and Croatia);
- Bekescaba – Nadab (between Hungary and Romania); and
- Florina – Bitola (between Greece and FYR Macedonia).

1.10 Results of the GIS

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. Scenario B is an unconstrained least cost development plan for all power systems in the nine jurisdictions operating as a completely integrated regional power system. Scenario C is based on a detailed hourly market simulation for two years (2010 and 2015) to determine actual operating conditions in the region, based on the generation expansion plan identified in Scenario B, as well as the proposed regional transmission system interconnections.

It is clear from all scenarios that investment in power generation is required in SEE. Without investment in plant refurbishment and in new capacity across the region, it is clear that the SEE power grid will not be able to meet the system reserve specifications of the UCTE operating requirements by 2010 (or earlier, depending on the timing of the decline in available capacity or on higher than forecast demand).

1.10.1 Scenario A results

The results of Scenario A illustrate the investment requirements based on the current plans of utilities looking at the electricity system within their own jurisdiction (with some view on the need for imports or ability for export). It encompasses a large volume of rehabilitation of existing thermal plant. We use the results to establish a base point against which we compare the investment needs of the region as a whole. Our key findings from considering the jurisdictions individually are:

- 15.5GW of new capacity would be required in the individual jurisdictions by 2020;
- 11.6GW of rehabilitated plant is planned over the period to 2020;
- The NPV of all construction and fuel costs would be €37bn;
- Construction cost of new capacity would be €12bn (in constant 2005 Euros); and
- Total construction cost would be €18bn.

1.10.2 Scenario B results

Scenario B was analysed to develop an unconstrained regional expansion plan to serve as the basis for the more detailed analysis to be undertaken in Scenario C. Sensitivity analyses were also performed to test the justification and timing of the rehabilitation programmes provided by the utilities.

The consideration of whether rehabilitation was more economic than the development of new plant (both specific candidates and generic plant) was central to determining the robustness of the results of Scenario B. The utilities' rehabilitation plans were used in the first instance, and then restricted according to economic criteria over three alternative scenarios. This analysis provided the "regional reference case" for further analysis under Scenario C. Looking at an unconstrained regional scenario suggested that:

- 11.0GW of new capacity would be required across the region;
- 11.5GW of rehabilitated plans is planned over the period to 2020, 60% in the period up to 2010 and 40% between 2010 and 2015;
- The NPV of all construction and fuel costs would be €34.1bn for the "regional reference case", a saving of €3bn on Scenario A;
- Construction cost of new capacity would be €9.5bn (in constant 2005 Euros) while total construction cost would be €15.4bn.

1.10.3 Scenario C Reference Case results

Under Scenario C, we consider the region in more detail, taking account of constraints on the network. Figure 1 shows the expected changes in existing capacity across the region, together with rehabilitation and new capacity, resulting from our Scenario C analysis.

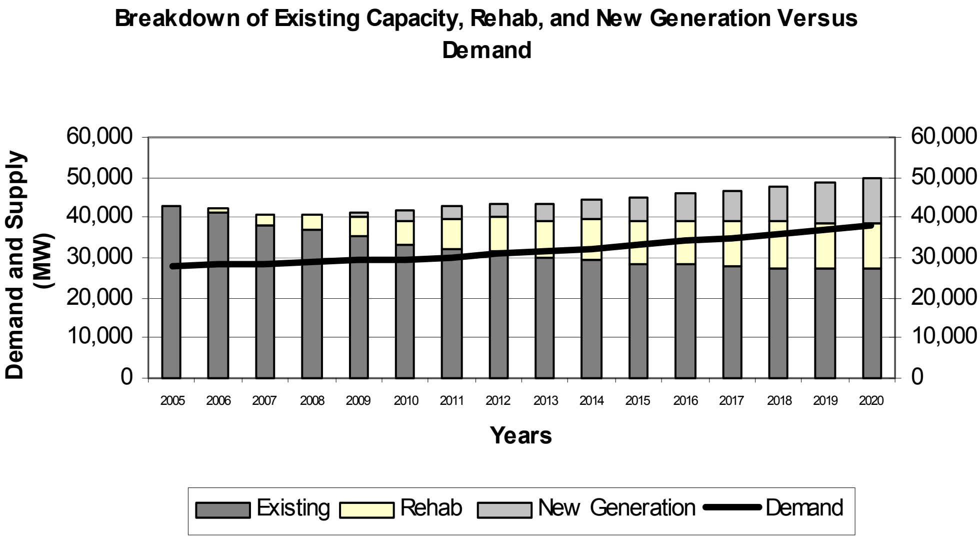

Figure 1: Scenario C Reference Case

The impact on regional capacity and energy generation mix is shown in Figure 2 and Figure 3.

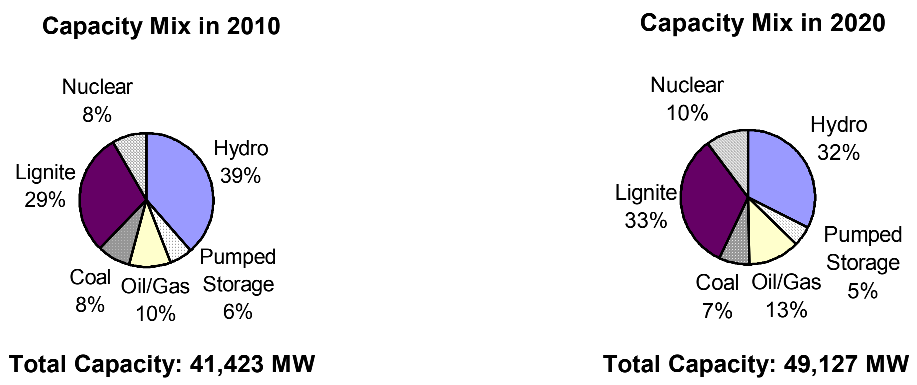

Figure 2: Capacity Mix for 2010 and 2020

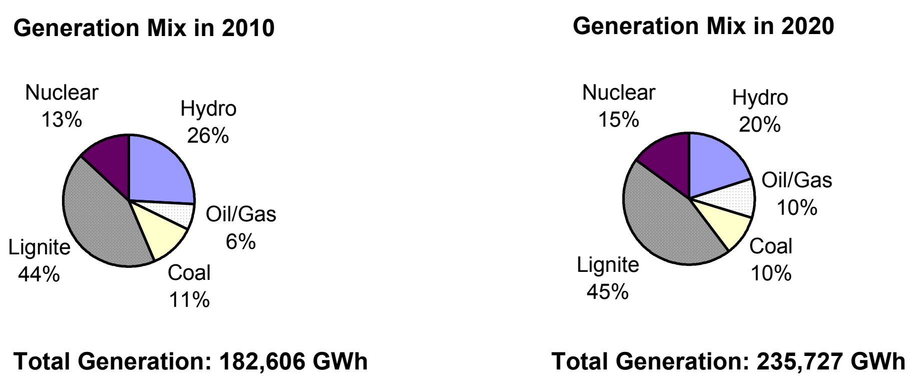

Figure 3: Generation Mix for 2010 and 2020

Key findings from the scenario C analysis are:

- 2.5GW of new capacity would be required by 2010. Of this:
  - 50% is expected to be lignite-fired;
  - 21% gas-fired; and
  - 26% nuclear.
- 11.0GW of new capacity would be required by 2010. Of this:
  - 45% is expected to be lignite-fired;

- 34% gas-fired; and
- 20% nuclear.

- 11.6GW of rehabilitated plant is planned over the period to 2020;
- Construction cost of new capacity would be €9.5bn (in constant 2005 Euros);
- Construction cost for rehabilitated plant would be €5.9bn;
- The total construction cost would be €15.4bn; and
- The NPV of all construction and fuel costs would be €34.1 billion (Reference Case). It varies from €29.5 (low demand) to €37.6 (high demand).

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), the 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 plant;
- Two 100-MW CHP plant; and
- Two 300-MW and one 500-MW combined cycle plant.

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.

1.10.4 Hydro sensitivity analysis

The expansion plan in Scenario C for the reference case did not include any new hydropower plant. A screening analysis was performed to select the most competitive regional hydro plant and a total of 2,112 MW were “forced” between 2010 and 2015. Although the total investments in new capacity including hydro increased by €1.5 billion, the total cost (€71.97 billion) increased only by €1.1 billion, due to savings in fuel costs. By comparison, the total cost would increase by €4.1 billion under a high gas price scenario. Hydro development appears to provide a protection against potential fuel price increases.

1.10.5 Summary of Scenario C Sensitivity Results

Table 3 compares the results of the Reference Case with five sensitivity cases that were performed. It should be noted that, in all cases, fuel and O&M costs vary between 75% and 80% of the total costs. Additional improvements in fuel supply and costs, unit efficiency, and maintenance procedures would have major impacts on total production costs.

Table 3: Results of Sensitivity Cases (€billion constant 2005 prices) – Non Discounted Costs

	Reference Case	Rehab Sensitivity	Forced Hydro	High Gas Price	High Load Demand	Low Load Demand
Construction cost for new capacity	9.524	12.501	11.036	11.488	14.022	5.234
Construction cost of rehabilitation and life extension	5.860	2.664	5.860	5.860	5.860	5.860
Fuel costs	35.246	32.181	34.503	36.628	37.969	29.592
O&M costs	20.254	20.862	20.550	20.980	22.016	18.683
Total costs	70.886	68.208	71.969	74.956	79.867	59.369

1.10.6 Regional costs

Table 4 presents estimates of average weekly marginal production costs in 2010 and 2015, under the three hydrological conditions. Hourly marginal production costs are computed from the fuel and variable O&M costs associated with the least-cost unit that would produce the next MW above current regional demand. The hourly production costs do not include any allowances for returns on equity investments or debt coverage. In running the various sensitivities, no regional transmission congestions were observed and therefore the hourly marginal costs were constant throughout the region. Due to variations in the level of seasonal load demand and hydropower generation, average weekly marginal costs show a wide variation between dry, average and wet conditions. As expected, marginal thermal costs are lower when there is a greater amount of hydropower available.

- In 2010, marginal production costs were determined to vary from €17.1 to €35.0/MWh; and

- In 2015, marginal production costs were determined to vary from €16.9 to €29.2/MWh.

Table 4: Average Marginal Production Costs for the Regional Market Operation in 2010 and 2015

	Weekly MPC 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.

1.11 Investment requirements

Figure 4 summarises the results of the Reference Case and key sensitivities analyses. They illustrate that there are two distinct phases of future investments:

- The first runs from 2005 – 2011 and is split fairly equally between rehabilitation and investment in new plant; and

- The second runs from 2012 – 2018 and is predominately new investments.

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 investment for this period. Figure 4 also summarises the required annual investments in rehabilitation and new capacity:

- The average annual construction cost for rehabilitation is about €665 million for the period 2005-2011;

- It decreases to about €232 million annually for the period 2012-2015;

- For new capacity, annual construction costs increase to €733 million by 2008; and
- Until 2018, annual construction costs fluctuate between €504 million and €929 million.

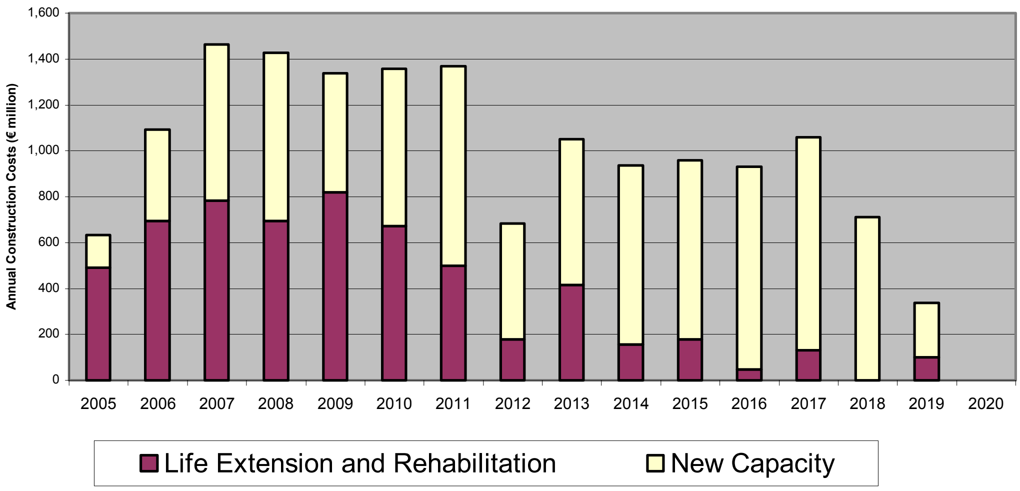

Figure 4: Annual Non-Discounted Construction costs (constant 2005 euros)

Table 5 illustrates the differences required in investments in new capacity and in fuel costs over the various sensitivities considered, and comparing the regional market to individual markets. It shows:

- Under the low demand forecasts, construction costs for new capacity are €5.2bn with a total fuel cost of €29.6bn;
- Under the high demand forecast, construction costs for new capacity are €14.0bn, with a total fuel cost of €37.9bn; and
- Under the high gas price scenario, construction costs for new capacity are €11.5bn with a total fuel cost of €36.6bn.

Table 5: Savings in New Capacity Investments and Fuel Costs (Non-Discounted € million)

		New Capacity Investment			Fuel Costs
Scenario	**Case**	**Total Costs**	**Savings**	**Total Costs**	**Savings**
A	Reference	12,122	NA	38,994	NA
C	Reference	9,524	2,598	35,246	3,748
C	Full Rehab	12,501	(379)	32,181	6,813
C	Forced Hydro	11,036	1,086	34,503	4,491
C	High Gas Price	11,488	634	36,628	2,366
C	High Demand	14,022	(1,900)	37,969	1,025
C	Low Demand	5,234	6,888	29,592	9,402
C	Imports	8,163	3,959	32,092	6,902

The difference in total costs of the reference case and Scenario A in Table 6 means that the benefit of considering investment and operation on a regional basis is €6.7bn in constant 2005 Euros, a saving of almost 10%.

Table 6: Comparison of non-discounted costs between the reference case and Scenario A

	For the reference case	For Scenario A (individual jurisdictions)
(constant 2005 Euros)	€bn	€bn
Construction costs for rehabilitation an life extension	5.9	5.9
Construction costs for new capacity	9.5	12.1
Total	15.4	18.0
Fuel costs over period	35.2	39.0
O&M costs over period	20.3	20.6
Total cost	70.9	77.6

1.12 *Transmission investments*

The GTMax and PSE/E models were also run for various cases under Scenario C, to analyse the adequacy of the regional network and the need for new investment. In general, the expected network topology for 2010 is sufficient to meet the generation and load patterns for year 2010 under the medium load forecast, except in South Serbia and Belgrade areas. Building the 400kV corridor Nis-Leskovac-Vranje-Skoplje would help resolve identified system operation problems. There are also a number of critical network elements in Romania that are overloaded. More detailed investigations and system operating studies are required to develop solutions and it is likely that additional transformer capacity in the sub-transmission system would be required. The level of reactive power consumption in Albania is also very high and should be investigated in more detail.

For 2015, the additional transmission lines proposed by the South East Europe Cooperative Initiative (SECI) would reduce losses in the region and allow normal operation of the regional network. As for 2010, reinforcement of the east-west corridor in Serbia is necessary. The proposed addition of 1,800 MW in TPPs based on 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 to determine the most appropriate solution. 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 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, Kashar-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 7 and Table 8. 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 7: 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 8: 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
	Belgrade	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.

1.13 Conclusions and recommendations

Overall, the results of the simulations demonstrate that there are significant benefits in considering investments on a regional basis in SEE. The 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 would be cost-effective under a range of scenarios. The most attractive plant from a regional perspective are:

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

The capacity expansion scenarios developed show a mix between gas-fired combined cycle and lignite power plant for new capacity. However, the mix of plant suggests there will not be a "dash for gas" in the region. Conventional hydro plant and pumped storage plant play a key role in meeting peak demand and reducing marginal production costs.

However, no hydro plant was 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, protection against high gas prices and long-term low production costs.

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, except for the units that are already committed or under construction. However, if rehabilitation were to become less economic (e.g. if environmental requirements were to become significantly more strict), this might change.

We highlight 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.

1.13.1 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.

1.13.2 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.

1.13.3 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.

1.13.4 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.

1.13.5 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.