ANALYSIS OF ECONOMIC AND FINANCIAL IMPACTS OF A SOUTHEAST-EUROPEAN ELECTRICITY MARKET

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The paper presents an analysis of the economic and financial implications of regional electricity interconnections and the establishment of a transnational power market spanning seven countries in southeastern Europe. The discussions introduce the underlying methodology and modeling approach based on the Generation-Transmission Maximization (GTMax) model. The power market analysis focuses on system conditions in the year when the regional electricity market is expected to become operational. The flexibility of the approach lends itself to quickly perform what-if analyses, such as comparing the economics of multiple power systems operating independently (isolated) with those resulting from joint operation within a regional/transnational electricity market (interconnected). For each scenario, the model estimates locational marginal prices (LMPs) of electricity at various geographical locations across the power systems in southeastern Europe and at power system interconnections. LMPs depend on the supply and demand equilibrium as well as on the transfer capabilities of the transmission network. Transmission congestion leads to price differentiation across zones, which is used to compute congestion line charges. Under the regional market, or interconnected scenario, power purchases and sales among systems are limited by total transfer capabilities on individual pathways or interconnections among systems; congestion also limits power transfers within each of the systems. Differences in LMPs under the isolated versus the interconnected scenarios are used to estimate the benefits of implementing southeastern Europe's regional power market. Benefits are measured as the difference in cost between individual system operations and joint, regional market operations. The analysis also estimates the financial implications for individual market participants, including transmission companies, generation companies, and consumers.

Keywords: Southeast Europe, regional electricity market, LMP, power transactions, GTMax.

1. INTRODUCTION

Southeast Europe is moving rapidly toward the creation of a regional electricity market. Argonne National Laboratory, in association with Montgomery Watson Harza, carried out a study entitled "Role and Value of Hydro and Pumped Storage in Southeast Europe," sponsored by the U.S. Agency for International Development. The objective of the study was to investigate potential benefits of a regional electricity market in Southeast Europe and possible impacts on the operation of hydro and pumped-storage plants in the region. The analysis focused on the power market situation in 2005, which is, according to the Athens Memorandum of Understanding, the target year for the operation of a regional electricity market for industrial and large (nonresidential) consumers.

The study simulated the operation of electric power systems of seven countries in Southeast Europe and built upon the previous studies performed by Argonne in the region. Included were the electric utility systems of Albania, Bosnia and Herzegovina (B&H), Bulgaria, Croatia, Macedonia, Romania, and Serbia and Montenegro. Turkey also participated in the project as an observer country but was not modeled. The analysis was performed using the Generation and Transmission Maximization Program (GTMax) developed by Argonne.

The study concluded that when the regional market starts operation, all of the countries can expect lower net energy supply costs. In general, regional market operation would allow for more cost-effective electricity production in the region by increasing the utilization of the most economical generating units and better optimization of hydro and pumped-storage dispatch. The study also shows that, in the regional market operation, hydro and pumped-storage plants can provide an even greater amount of ancillary services than if the utility systems operate independently. The results obtained from the study are now being used for regional transmission planning studies to evaluate proposed investments into new transmission interconnections.

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This paper presents some of the main results of the analysis, focusing especially on the comparison of operating costs of power systems obtained for the isolated and interconnected (regional market) operation.

2. ANALYTICAL METHODOLOGY

GTMax is Argonne's premier software tool for the detailed analysis of utility systems operations and costs in an open market. With GTMax, utility operators and managers can maximize the value of the electric system, taking into account not only its own limited energy and transmission resources but also firm contracts, independent power producer (IPP) agreements, and bulk power transaction opportunities on the spot market. GTMax maximizes net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. GTMax does this while ensuring that market transactions and system operations are within the physical and institutional limitations of the power system. When multiple systems are simulated, GTMax identifies utilities that can successfully compete on the market by tracking hourly power transactions, locational marginal prices (LMPs), generation costs, and revenues.

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. GTMax calculates market prices for electricity sales/purchases in different regions (market hubs) of the power network based on the capacity constraints of transmission interties. The model simultaneously optimizes power transactions to minimize overall operating costs in the region.

The analysis was carried out for four typical weeks in 2005 (winter, spring, summer, and autumn). GTMax was used to simulate hourly system operations during the 3rd week of January, April, July, and October of 2005. Each utility system was first simulated as operating independently, without the connections with other systems. This was the so-called "individual operation" scenario. Then, all of the utility systems were connected into a regional network, and GTMax was used to simulate the hour-by-hour operation of the regional electricity market ("regional market" scenario).

Under both scenarios, the utility systems of the participating countries were represented with the generation and transmission facilities that correspond to the expected system configurations in 2005. Similarly, under the regional market scenario, the utility systems were interconnected into a regional network with the existing interconnection lines and with those that are expected to be in operation in 2005. The power transfer capabilities of the interconnection lines were also taken into account during the GTMax simulations of the hourly operations of a regional electricity market. In principle, for the simulation of a regional electricity market, GTMax was used to calculate hourly values of LMPs for all nodes (market hubs) of the regional network and to optimize power transactions among the utility systems. Power transactions were subject to the capacity limits (net transfer capabilities) of the interconnection links among the systems.

3. REGIONAL ELECTRICITY NETWORK

The topology of the network that was configured in GTMax for the participating countries is shown in Figure 1. GTMax computes market prices of electricity at various geographical locations within the power systems and at power system interconnections. The market price is assumed to be the marginal cost of delivering energy to a specific location. The companies that generate power are paid the LMP at the point of power injection; that is, the price is dependent on the supply and demand equilibrium. In this analysis, it is assumed that generators bid energy blocks into the market at marginal production costs.

Another factor in determining LMPs is the transmission network and its transfer capabilities. In principle, if there is no transmission congestion, power can be transferred to any node of the network and all nodes have approximately the same LMPs. However, in the case of transmission congestion, the transport of power to a particular region in the network may be limited by the transfer capabilities of the transmission lines connected to that particular area, thus creating a zone with higher LMPs. Differences in LMPs between two connected regions are used to compute congestion line charges. In this study, the analysis of regional market operation was performed taking into account possible transmission congestion on the interconnection links among the power systems. No internal transmission congestion was considered within individual utility systems.

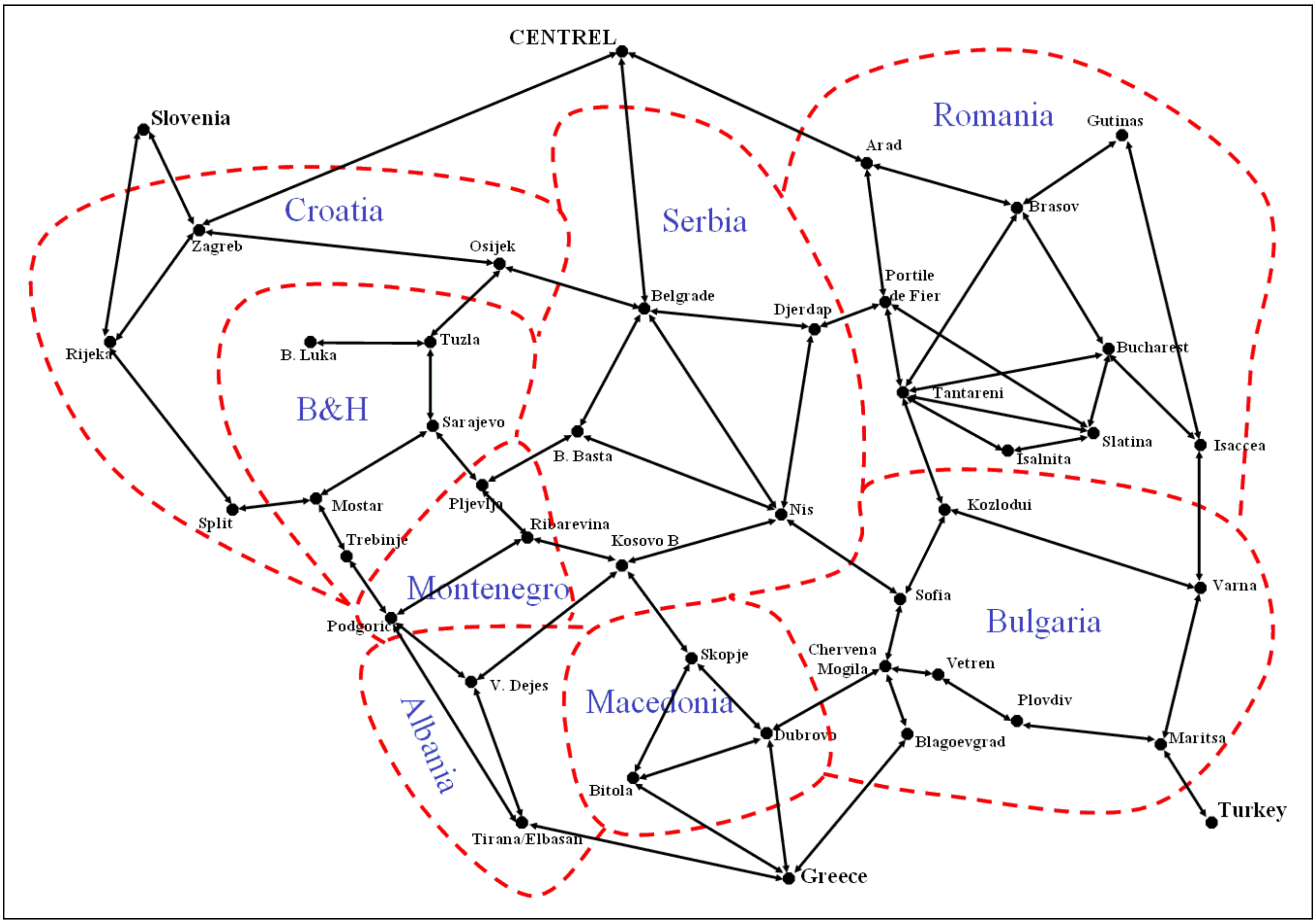

Figure 1: Simplified GTMax Representation of the Southeast Europe Regional Network in 2005

4. INDIVIDUAL AND REGIONAL MARKET ANALYSIS

The GTMax model was first used to analyze the operation of individual utility systems and then to analyze the regional market operation. The results obtained for these two scenarios served as a basis to determine the cost differences between the operation of individual systems and operation of the regional market. These cost differences provide an indication of possible economic benefits of integrating the operation of the power systems in the region. Most benefits and cost savings are expected to be attributable to load diversity, more efficient dispatch of generating units, reduced spinning reserve requirements, and greater system reliability.

Under the individual operation scenario, the power systems operate independently and do not trade, sell, or exchange energy or capacity with each other. The results of this scenario reveal electricity generation costs in each of the utilities under the assumption that the systems are operated as isolated entities. Therefore, each system is responsible for satisfying its own electricity demand by means of its own generation resources while maintaining an adequate level of spinning reserve to ensure system reliability.

On the other hand, the regional market scenario allows for power exchanges among the utility systems via the interconnection links. In this scenario, the GTMax model was used to determine the potential for power transactions, optimal energy exchanges, and nodal market prices.

5. RESULTS AND DISCUSSION

The results of the analysis show that the regional electricity market provides significant benefits and operational savings compared to the operation of individual utility systems. Figure 2 provides an illustration of the total weekly operating costs for the regional electricity market compared to the sum of weekly operating costs of individual utility systems. These results are presented for typical weeks in different seasons of 2005 for three hydrological conditions (wet, average, and dry).

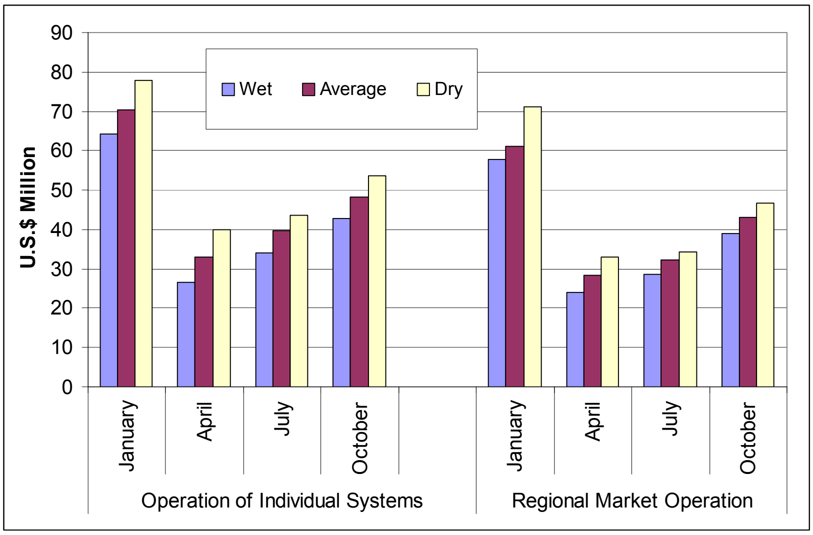

Figure 2: Total Weekly Variable Costs by Hydro Condition

The estimated savings in operating costs are presented in Table 1. Depending on the season, the total weekly savings for the entire region range from 2.7 to 9.1 million U.S. 2000 dollars. Most of the benefits occur in July under the dry hydrological condition. The smallest savings are found in April under the wet hydrological condition. In principle, the largest cost savings are realized under the dry hydrological condition ($7.5 million average savings in four typical weeks), then under the average hydrological condition (average $6.5 million), and the smallest savings are achieved under the wet hydro condition (average $4.6 million). In terms of percentage savings compared to the operation of individual systems, the results show an average of 11.3% savings under the wet hydrological conditions, 13.9% savings under the average, and 15% savings under the dry hydrological conditions. These are the average cost savings for the four analyzed weeks in different seasons of the year.

Table 1: Estimated Weekly Savings in Operating Costs

3rd Week Only	Operating Cost Savings (U.S. $ Millions)		
	Wet	Average	Dry
January	6.7	9.1	6.6
April	2.7	4.5	7.1
July	5.3	7.5	9.1
October	3.8	4.9	7.0
Average Weekly Cost Savings	4.6	6.5	7.5
Approx. Annual Cost Savings	241.0	338.1	387.7
Average Cost Savings (%)	11.1	13.6	13.9

The estimate of the approximate annual cost savings that can be achieved in the regional market operation for the three different hydrological conditions are illustrated in Figure 3.

The GTMax results also show that the average electricity production costs in the region are significantly lower for the regional market operation compared to the operation of individual utility systems. Figure 4 provides a comparison of the average electricity production costs in the region in different seasons during the year and under different hydrological conditions. The costs shown in Figure 4 are the variable costs of electricity generation (e.g., fuel costs and costs of electricity purchases) and do not include fixed costs (e.g., fixed O&M and capital costs). Since the fixed component of the electricity generation cost is identical for both scenarios, Figure 4 shows that regional electricity market operation results in lower average costs of electricity generation in all analyzed time periods (seasons) and under all hydrological conditions.

GTMax was also used to calculate hourly LMPs in each node of the regional network. An illustration of LMPs by country is presented in Figure 5, which provides a comparison of the average weekly LMPs for the utility systems in the 3rd week of October under average hydrological conditions. In the operation of individual utility systems, LMPs show wide variations from system to system, depending on the plant mix and internal generation costs. On the other hand, in the regional market operation, the LMPs show less variation and tend to equalize the prices of electricity across the region. In the regional electricity market, the variations in LMPs mostly occur when there is transmission congestion in some parts of the network.

In the GTMax simulations, each utility system was required to provide a certain amount of regulation and contingency reserves. The assignments of reserve capacity for regulation (area load control) and for contingency reserves (spinning and nonspinning) to be maintained by individual power plants were optimized by GTMax on an hourly basis. Integrated operation in an interconnected regional electricity market allows for savings in ancillary services, especially in providing the contingency reserves. Compared to

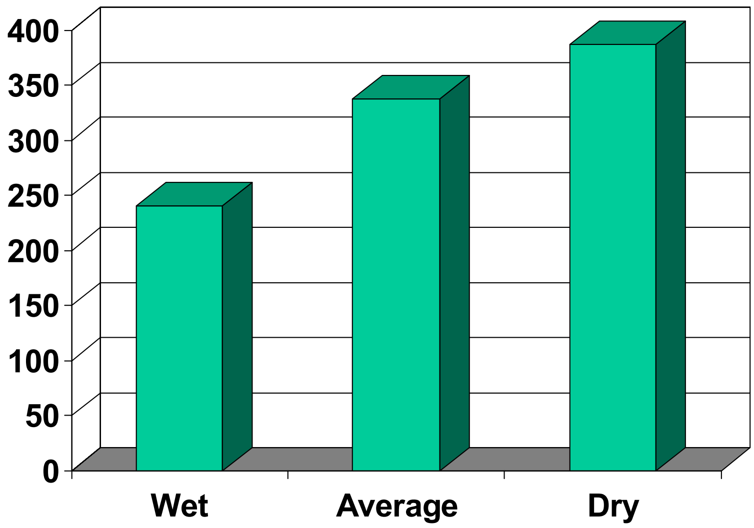

Figure 3: Estimated Annual Cost Savings (U.S. $ Millions) for Different Hydrological Conditions

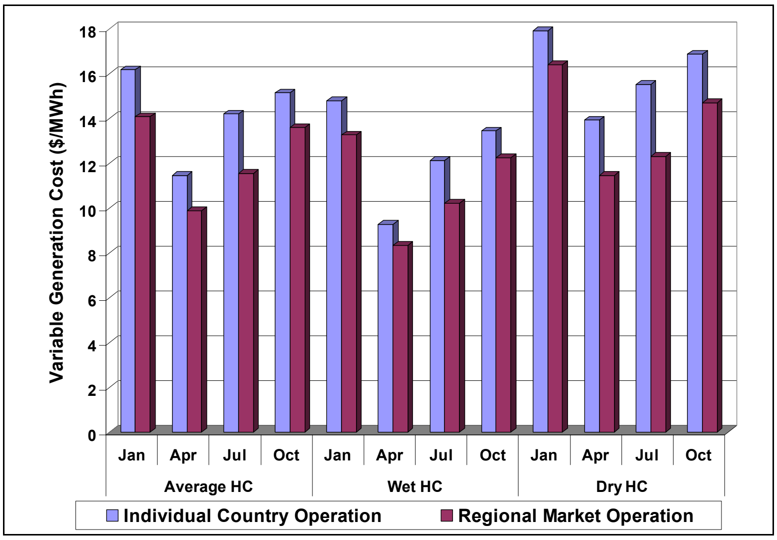

Figure 4: Comparison of Average Costs of Electricity Generation

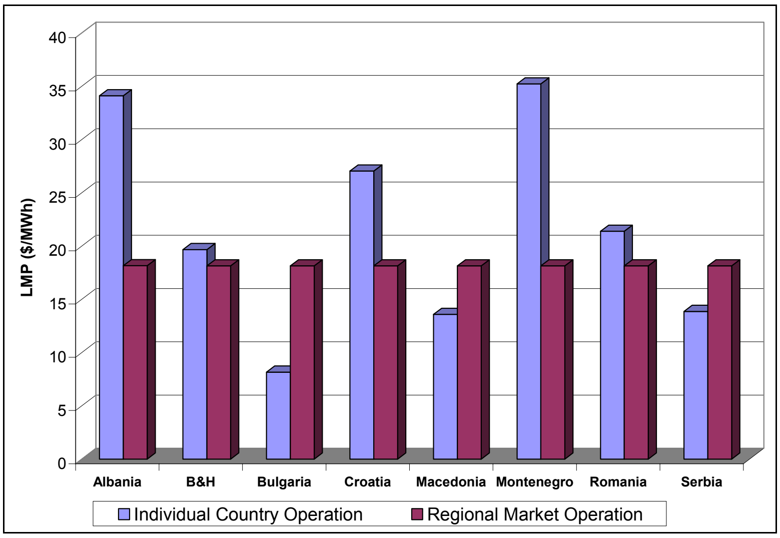

Figure 5: Average LMPs by Country for 3rd Week of October 2005 under Average Hydrological Conditions

the operation of individual systems, all utilities had to provide significantly lower amounts of contingency reserve in the integrated regional operation scenario.

Hydro and pumped-storage plants provide most of the ancillary services in both the independent and regional market operations. The contribution of thermal power plants to ancillary services is relatively small and even decreases further under the regional market scenario. In the operation of individual systems, the contribution of thermal capacity to the total regulation reserve averaged about 121 MW, or 16.6% of the total. This contribution decreased under the regional market scenario to an average of 76 MW, or 10.5% of the total. In the case of contingency reserves, the contribution of thermal capacity was already very small (about 1%) in the operation of individual utility systems and decreased to zero in the regional market operation.

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