POTOMAC ECONOMICS

National Association of Regulatory Utility Commissioners

USAID FROM THE AMERICAN PEOPLE

DRAFT REPORT
ON
SOUTH EAST EUROPE MARKET MONITORING

FOR THE PERIOD

DECEMBER 2006-FEBRUARY 2007

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I. OVERVIEW

This is the first report providing an account of market monitoring activities under the South East Europe market monitoring Pilot Plan initiated by the United States Agency for International Development (USAID) and the National Association of Regulatory Utility Commissioners (NARUC). This report covers the period December 2006-February 2007.

The Pilot Plan originated at the 8th Athens Forum in June 2006 when the Forum invited USAID to move forward on its proposal for market monitoring. USAID, in conjunction with NARUC, assembled a team of consultants to develop the Pilot Plan. The consulting team includes Dr. Peter Kaderjak of the Regional Energy Policy Center (REKK) at Corvinus University in Budapest, Dr. David Newbery of the Energy Policy Research Group (EPRG) at Cambridge University in England, and Dr. Robert Sinclair of Potomac Economics in Fairfax, Virginia.

On November 16, 2006, USAID and NARUC sponsored a Market Monitoring Design Workshop in Brussels, Belgium for participants to provide input into the market monitoring plan. Drawing on the workshop commentary, the consulting team developed a market monitoring plan that relies on a phased-in approach. This approach directs the initial focus of the Pilot Plan on the cross-border transmission capacity market, enlarging the scope in subsequent phases to the monitoring of activities in generation markets.[1]

A. The Market Monitoring Plan

The market monitoring plan is proposed to be in three phases. The current phase is Phase I and is the subject of this report. In this Phase we focus on the cross-border transmission capacity market, although some limited activity is occurring relating to the wholesale generation market. In this Phase, which is expected to be completed in the second quarter, we rely on limited data from the participating entities and seek to augment our market monitoring using public data.

Phase II of the plan introduces advanced monitoring of the cross-border transmission capacity market and initial monitoring of wholesale generation markets. Advanced monitoring will require additional data and this data will be identified during Phase I, in particular, in this report.

[1] The Market Monitoring Plan is located on the SEE Market monitoring website at: : http://www.naruc.org/see_monitoring/docs/SEE_Market_Monitoring_Plan_DRAFT_12_01_06_Web.pdf

As explained herein, we propose Phase II to be a broadening of our range of monitoring activities and data requests. Primarily, we expect to request data related to the calculation of NTC and ATC under the capacity assessment, data on sales and purchases, data on congestion management, and generator operating data.

The initial monitoring of wholesale generation markets in Phase II, like the initial monitoring of the cross-border transmission capacity market in Phase I, will rely on a combination of publicly-available data and non-public data that will be requested in limited measure. We will use this initial data as well as any findings from Phase I to identify key issues and to identify the scope of any data requirements judged to be needed on a going-forward basis. A second quarterly report will be drafted and circulated among the interested parties for comments this summer.

By staggering the initial analysis of the cross-border transmission capacity market and the wholesale generation market, the Pilot Plan reflects requests to initiate the market monitoring on a reduced scale with targeted issues and screens.

Phase III will begin in the summer of 2007 and will run until the end of the year. The advanced analysis of the cross-border capacity market will continue through Phase III. In addition, advanced monitoring of the wholesale generation market will begin. Phase III will be shaped by commentary received from our reporting in Phase I and Phase II. We anticipate the work will include modeling of regional electricity supply to identify potential areas of market power concern that would help focus monitoring analyses. A third and fourth quarterly report will be provided during this phase. These reports will contain data analysis, screens, and a summary of key competitive findings. In addition, another progress report will be given at the fall Athens Forum.

B. Summary of Report

1. Data Procurement

Our activities are facilitated through contact with the transmission system operators ("TSOs") in the region. There are nine TSOs in the Pilot Plan. Herein we refer to this group alternatively as "Participants" or "TSOs". The main activities in Phase I were initiated with a limited request for data that was sent to each Participant in January. This data request sought load and generator

data and hourly power flows at each interconnection for December 2006. Appendix A shows this first data request. The same data request was sent again on February 14 for January data and on March 12 for February data. The two data requests sent in February and March were modified from the original data request related to the generator data because there was no need to update all aspects of the generator data each month.

With the exception of Bulgaria, all participants responded favorably to our data requests. We continue to seek cooperation from Bulgaria and individual personnel in these countries have been working to secure that cooperation. Among the other participants, we are satisfied with the level of cooperation. The data was provided in a useful format and aside from a few claims to confidentiality of certain data, especially with respect to generator data, these objections did not prevent us from moving forward on our program.

2. Network Constraints

Our analysis of network constraints focuses on two indicators. We are first interested in the availability of cross-border transmission capacity through the capacity assessment, which is a procedure for calculating Net Transmission Capability (NTC) and Available Transmission Capacity (ATC). When ATC is zero or close to zero, this indicates limits on additional market activity and potential market failure.[2] We are also interested in congestion management procedures that may lead to curtailment of transactions.

ATC Values. Net Transfer Capacity ("NTC") and Available Transfer Capacity ("ATC") calculations are coordinated among TSOs in accordance with guidelines promulgated by the European Transmission System Operators ("ETSO"). There are 22 interconnections linking the Pilot Plan participants. We collected ATC values on 18 of them. All of these 18 paths had at least a small amount of ATC posted in all three of the months December through February. On 7 paths ATC was less that 50 MW in one or more of the months studied and on 13 paths it was less than 100 MW. In general, the wide availability of ATC indicates reserving capacity has not been a pervasive problem.

[2] As explained below, the standardized capacity assessment does not eliminate the possibility of unreasonably restrictive practices in establishing available capacity to the market. However, any monitoring of the underlying details of the NTC and ATC calculations that would illuminate these issues would be initiated in a latter phase of this Pilot Plan.

Congestion Management Procedures. Congestion management procedures are designed to ensure reliable use of the transmission network when network transactions cannot be securely accommodated. Congestion management becomes a market monitoring issue in instances when transactions have to be curtailed or otherwise degraded in order to achieve network security. In this phase of the Pilot Plan, we have not sought data on this issue. However, as explained herein, for Phase II we proposed additional data to monitor instances of congestion management measures that can adversely impact the market.

3. Monitoring Activities

Cross-Border Transmission Capacity. The calculation of ATC values in South East Europe through the capacity assessment process is a critical component of the cross-border transmission capacity market. We conduct two analyses. First, we compare the posted capacity reservations to the actual line flows to determine if the flows are consistent with what is being set aside for "already-allocated" uses of the system in the capacity assessment process. Our analysis is preliminary in that additional data is required for a more precise comparison. However, it provides a useful overview of allocation and usage of interconnection capacity.

Our second analysis examines the key data elements of the capacity assessment itself to determine the best way to monitor such a process on a forward-going basis. As explained herein, the capacity assessment requires the accurate input of a variety of forecast values and operational parameters. Inaccurate reporting of these values can adversely affect the availability of cross-border capacity. We evaluate this process and identify the key data that should be monitored to help ensure competitive outcomes in the market.

*Congestion and Sales and Purchase*s. Critical attention is given to ATC constraints and congestion in the context of market monitoring because at these times and locations the market is most likely to fail, leading the way for anticompetitive conduct. The key data required for this analysis is the sales and purchases data. At this phase of the market monitoring Pilot Plan, data is not sufficient to conduct analysis of constrained periods.

One of the primary means to achieve effective market monitoring is access to market transactions in order to determine whether periods of congestion have provided the opportunity to exploit market power. As explained below, the effectiveness of the market monitoring plan

would be greatly enhanced if sales and purchases data were to be available for screening in instances when congestion occurs.

Congestion Management. We use congestion management measures as indicators of congestion but they are also the subject of monitoring as well. If congestion management measures are applied when they are unnecessary this could result in market distortions. While this data has not been requested in Phase I, we propose to request congestion management data for Phase II.

4. Generation Market Modeling

The consulting team also conducted preliminary work on developing a regional generation market model. This model will be used as a monitoring tool to identify (1) what outcomes (in terms of prices, production, trade etc.) an efficiently working market would yield; (2) what separated submarkets could develop in a geographically dispersed region; (3) whether any producer has the incentives and means to exercise its market power (if it exists); and (4) what the overall market outcome could look like if producers freely exercised their market power. The generation model will be a primary tool of the market monitoring of the generation sector in latter phases of the Pilot Plan.

5. Scope for Phase II

Phase II of the Market Monitoring Pilot Plan will begin upon final publication of this report in April. For Phase II, we propose to expand the scope of the monitoring plan for both the cross-borer transmission capacity market and the wholesale generation market.

For the cross-border transmission capacity market we will seek additional data and analysis in three main areas. First, we seek additional data associated with the capacity assessment process. In particular, we will request data associated with key assumptions of the regional planning model which estimates the cross-border capacity. We will also request details on congestion management procedures and actions taken that lead to cross-border curtailments. The third main area into which we seek to expand monitoring is in the sales and purchases activities. In the interest of meeting our commitment to adhere to a phase-in of the Pilot Plan, in Phase II we are requesting additional information on the format and availability of sales and purchase data with the intention of requesting this data at a latter phase of the project.

The Pilot Plan will also continue activity in development of the regional generation market model as discussed herein.

II. WHOLESALE PRICES AND TRANSACTIONS

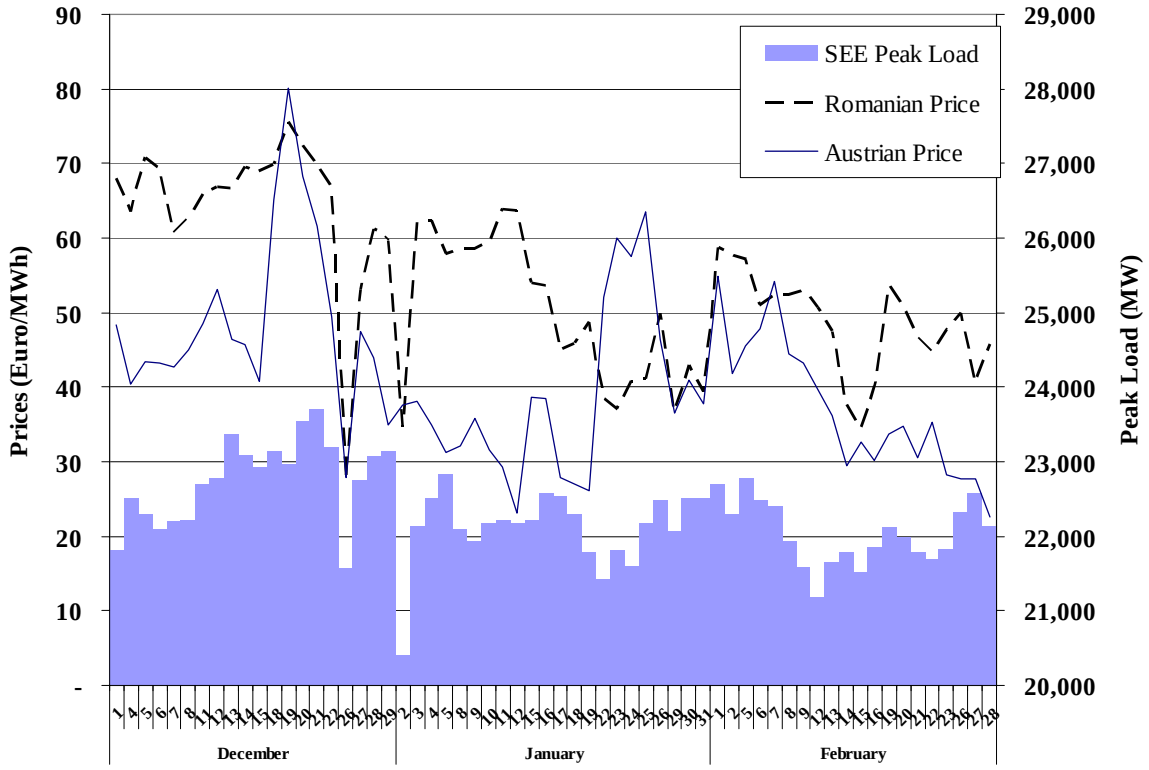
Summary statistics on overall regional market prices and volumes of transactions can contribute to effective market monitoring. Understanding price levels and patterns can provide insight into specific time periods and locations that can help focus market monitoring resources. South East Europe is not integrated into a centralized-spot market like other parts of Europe like NordPool in Northern Europe and National Grid in the U.K. Wholesale market activity in South East Europe is conducted mainly under bilateral contracts among utilities and traders. There is no publicly-available price index for bilateral trades on a region-wide basis.

However, the Romania spot market and the Austrian spot market prices provide an overview of the price movements during the time period of this report. While the spot prices will not always correspond to all wholesale trades, they should be highly correlated. In the subsequent phases of the market monitoring Pilot Plan, we propose requesting bilateral contract data from each participant and from this we can construct a bilateral price index that would more closely track the market activity.

Figure 1 shows the daily average price of electricity in Romania and Austria along with the peak load each day for entire SEE region.

The figure indicates some correspondence between regional load and the day-ahead spot prices. While this does not necessarily indicate the absence of market failure, it does show some degree of liquidity because prices are relatively responsive to load variation. It also reveals no serious market dislocation over the period studied.

Figure 1: Romanian Spot Market Prices and SEE Load
December 2006 – January 2007



As noted above, the price-load relationship is to provide an indication of a particular time period deserving special attention. What stands out is the divergence of prices between Austria and Romania at certain times, indicating the lack of market capacity (either physical or institutional) to arbitrage the regional markets. While this lack of arbitrage is related to the overall efficiency of trading in the region, it is not a direct concern of this monitoring plan at this time.

Sales and Purchases. Market activity in South East Europe is primarily conducted through bilateral contracts for cross-border trades. Some limited trade is also conducted within countries. The data on these sales and purchases is not public. Therefore, at this phase in the monitoring we do not make further analysis.

We propose to initiate collection of this data in subsequent phases of the Pilot Plan. We would seek short-term trades because these would be the one most easily used to exploit congestion. In this section we only summarize the overall aggregate sales activity. In Section, IV.B we

propose to develop screens to investigate any link between sales prices and congestion events in order to determine the existence of potential anticompetitive activity.

III. NETWORK CONSTRAINTS

Network constraints can arise in the real-time as well as in the planning horizon. In the planning horizon, constraints arise as a result of limits on transmission capacity. In real-time (or near real-time, like day ahead), constraints arise from network congestion due to unit commitment or dispatch. Our analysis of constraints in Phase I is concerned with the planning horizon, focusing on the capacity assessment on cross-border interconnections that establishes the ATC. In Phase II, we will collect data to determine constraints in real-time through analysis of curtailments or other real-time measures.

NTC and ATC calculations under established y TSOs using standard procedures promulgated by the European Transmission System Operators ("ETSO").[3] We use monthly ATC values as indicators of constraints in the region. If ATC is zero at a particular interconnection,[4] the network is constrained because no incremental market activity can occur that relies on the particular interconnection. There are 22 interconnections that link the Participants in the Pilot Plan. Of these interconnections, we were able to obtain ATC data on 18 of them (missing data for Bulgaria prevented compiling data on the four others). All of these 18 paths had at least a small amount of ATC posted in all three of the months December through February. The summary of these interconnections and monthly ATC values is shown in Table 1.

These monthly values are not adjusted for allocations from monthly auctions that have been initiated on many of the interconnections starting in January. We anticipate including these allocations in subsequent reports. Therefore, the ATC reported herein is the upper end of the ATC that would have been available after the auction; on some interconnections the ATC could be less if additional capacity was allocated in the auctions.

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3 See "Procedures for Cross-Border Transmission Capacity Assessments," ETSO, October 2001; "Definition of Transfer Capacities in Liberalised Market", *Id*. April 2001.

4 By "interconnection" we mean what is commonly understood in the region as the electrical interface between two neighboring control areas.

Table 1: Summary of Monthly ATC Values

Interconnection	ATC		
	Dec 06	Jan 07	Feb 07
Albania to Montenegro	200	170	200
Albania to Serbia	315	315	315
Bulgaria to Romania	Unavailable		
Bulgaria to Serbia	Unavailable		
Bosnia & Herzegovina to Croatia	50	380	460
Bosnia & Herzegovina to Montenegro	78	474	474
Bosnia & Herzegovina to Serbia	10	250	286
Croatia to Bosnia & Herzegovina	400	190	250
Croatia to Serbia	175	350	350
Macedonia to Serbia	150	220	75
Montenegro to Albania	87	75	100
Montenegro to Bosnia & Herzegovina	290	410	390
Montenegro to Serbia	450	500	400
Romania to Bulgaria	Unavailable		
Romania to Serbia	256	200	225
Serbia to Albania	55	55	55
Serbia to Bulgaria	Unavailable		
Serbia to Bosnia & Herzegovina	50	200	150
Serbia to Croatia	150	300	250
Serbia to Macedonia	30	130	170
Serbia to Montenegro	200	400	300
Serbia to Romania	190	50	75

Note: Monthly ATC Values prior to any monthly auction. ATC for interconnections with Bulgaria unavailable due to lack of Bulgarian data.

As the table indicates, on 7 paths ATC was 50 MW or less in one or more of the months studied and on 13 paths it was 100 MW or less. In general, the wide availability of ATC indicates reserving capacity has not been a problem. However, more than one-half of the paths indicated ATC of 100 MW or less during the period. This indicates that large trades of 100 MW or more for which ATC is not already reserved would have to be forgone or reduced. We have not gathered the data at this stage of the monitoring plan that would enable us to indicate whether such transfers were abandoned as a result of too little ATC.

Finally, as explained below, the standardized capacity assessment does not eliminate the possibility of unreasonably restrictive practices in establishing available capacity to the market.

However, any monitoring of the underlying details of the NTC and ATC calculations that would illuminate these issues would be initiated in a latter phase of this Pilot Plan.

In addition to congestion arising from the lack of or low ATC values, we also propose to gather data on events associated with congestion management measures. In the next phase of the market monitoring plan, we will seek data on congestion management measures. When measures are taken that curtail or limit cross-border trades, we will consider that to be an incidence of congestion.

The overall purpose of identifying congestion events in the region is to focus market monitoring resource to times and locations that are most susceptible to market failure. For example, as explained in the next section, at times of congestion, sales and purchases activity would be screened to detect any evidence of market power.

IV. DIRECT MONITORING ACTIVITIES

In the previous sections, we examined overall market conditions and identified network constraints. Such analysis helps to focus the monitoring to times and locations when market power is most likely to arise as well as times and locations when it would be most costly to the market. In this section of the report we address the more direct market monitoring. There are four main aspects of this direct monitoring. The first is the management of the interconnections. The monitoring in this regard is associated with the calculation of available transmission capacity and is in two parts. We first monitor line flows over the various interconnections among South East Europe participants to compare these flows with reserved capacity on the interconnections. We also address the capacity assessment itself, something that will continue in earnest in Phase II.

The second main aspect of the direct market monitoring is the analysis of sales and purchases in the context of network congestion. We have not begun collecting the data necessary for this aspect of the Pilot Plan. However, we will discuss the potential analyses and the data required going forward.

The third main aspect of the direct monitoring is the monitoring of congestion management measures taken, especially as they relate to cross-border flows. Like with the sales and

purchases analyses, we have not begun to collect data that would enable us to initiate monitoring. We discuss herein data requests that would allow monitoring on a going-forward basis.

The fourth main aspect of the direct monitoring is the generation market power monitoring. Some preliminary work has been initiated in this area but the direct monitoring will commence in latter phases of the Pilot Plan. Herein we discuss this initial work and the scope of work going forward.

A. Monitoring Capacity Assessment

The Capacity Assessment is the process used by the South East Europe Participants (indeed all European countries that are party to the Internal Market of Electricity of Europe). Promulgated by ETSO, the Capacity Assessment establishes a standard process to calculate and harmonize the Net Transfer Capacity (NTC) values among interconnected areas. We conduct our monitoring in two parts. We first compare the actual interconnection power flows and NTC and ATC values to determine how the interconnections are being used. We then evaluate more closely the capacity allocation process to determine the monitoring approach on a going-forward basis.

1. Interconnection Flows

As discussed above, there are 22 interconnections that link the Pilot Plan participants. Not all participants provided the line flow data that was needed to accomplish the analysis. However, if at least one party to the interconnection provided line flow data then it was possible to continue the analysis. However, in the case of the Bulgaria-Serbia interface, the analysis was not possible because line flow data was not provided by either party to the interconnection.[5] We are hopeful this data will be forthcoming in latter phases of the Pilot Plan and we continue to work with these participants to procure this data. A much more serious hindrance is the lack of ATC data. We have not been able to locate ATC data for Bulgaria. Without this data, no interconnection that includes these participants can be evaluated under this analysis. We continue to seek ways to locate this data.

[5] In the case of Bulgaria, this data was not supplied because there was no response at all to data requests under this project. In the case of Serbia, the TSO was adhering to what it interpreted as its obligations under certain confidentially provisions.

When data is sufficient, the analysis is straightforward: we compare actual power flows over an interconnection with the amount of capacity that was allocated for various network uses. As explained in more detail below, NTC is the maximum transmission capacity between two areas base on a reference (simulated) base case. It is determined by estimating the maximum power flows that can safely be accommodated over the interconnection given forecast uses of the regional system (including loop flow) and a Transmission Reliability Margin (TRM).

The NTC, reduced by Already-Allocated Capacity (AAC) is the ATC, which is the transmission capacity available to the market.[6] AAC is the transmission that is reserved for anticipated exchanges and transactions. If AAC is reserved in a manner to reflect anticipated uses of the transmission network, and these anticipated conditions are realized (and loop flow is minimal), then the actual power flows should correspond to the AAC, at least at the time of the monthly peak, the time horizon for which AAC and NTC are calculated.

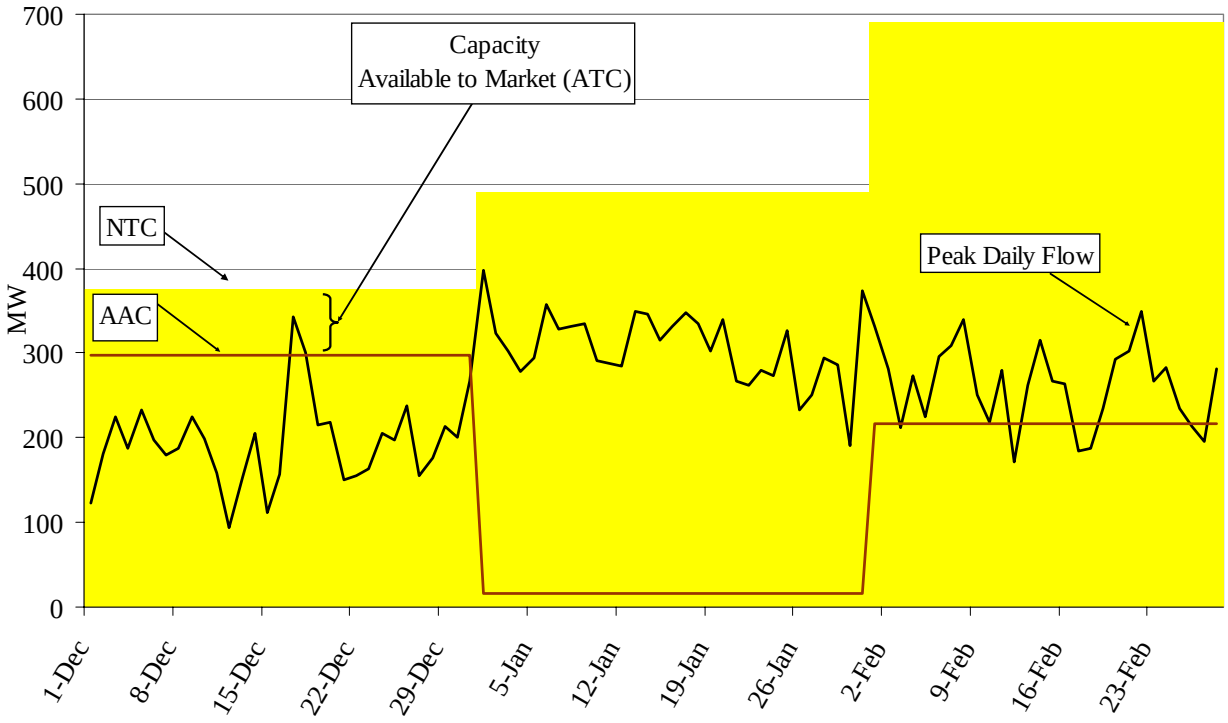
If AAC and power flows do not match, then one or more of the following conditions may be true: (1) too much or too little is being allocated to serve the interconnection demand; (2) operational factors are in play that are not (or cannot be) accounted for in the modeling; and/or (3) loop flow on the interconnection is significant. If (1) or (2) is true or if (3) is true and unexpected, then ATC could be understated and competition may be negatively impacted. Accordingly, our analysis seeks to determine the difference between AAC and actual flows in order to establish the starting point for considering the source of any significant divergence for future monitoring.

Our analysis herein is considered preliminary because, as noted above, we do not yet have the full data necessary to determine total AAC (something we seek to remedy) and we do not reflect loop flow. Nonetheless, the analysis can provide important insights as long as it is kept in mind that certain conditions may mitigate or aggravate the conclusions.

[6] As discussed above, we use monthly NTC and ATC values but have not accounted for the results of monthly auctions on interconnections where these auctions take place. The monthly auctions will result in additional ATC being allocated. We have started to collect this data starting with the April data request. The analysis herein, as we note, will overstate ATC and understate AAC. Accordingly, we qualify our analysis to account for this missing data.

We move now to the analysis of individual interconnections. We begin with Bosnia & Herzegovina to Montenegro shown in Figure 2.

Figure 2: Power Flows Bosnia & Herzegovina to Montenegro



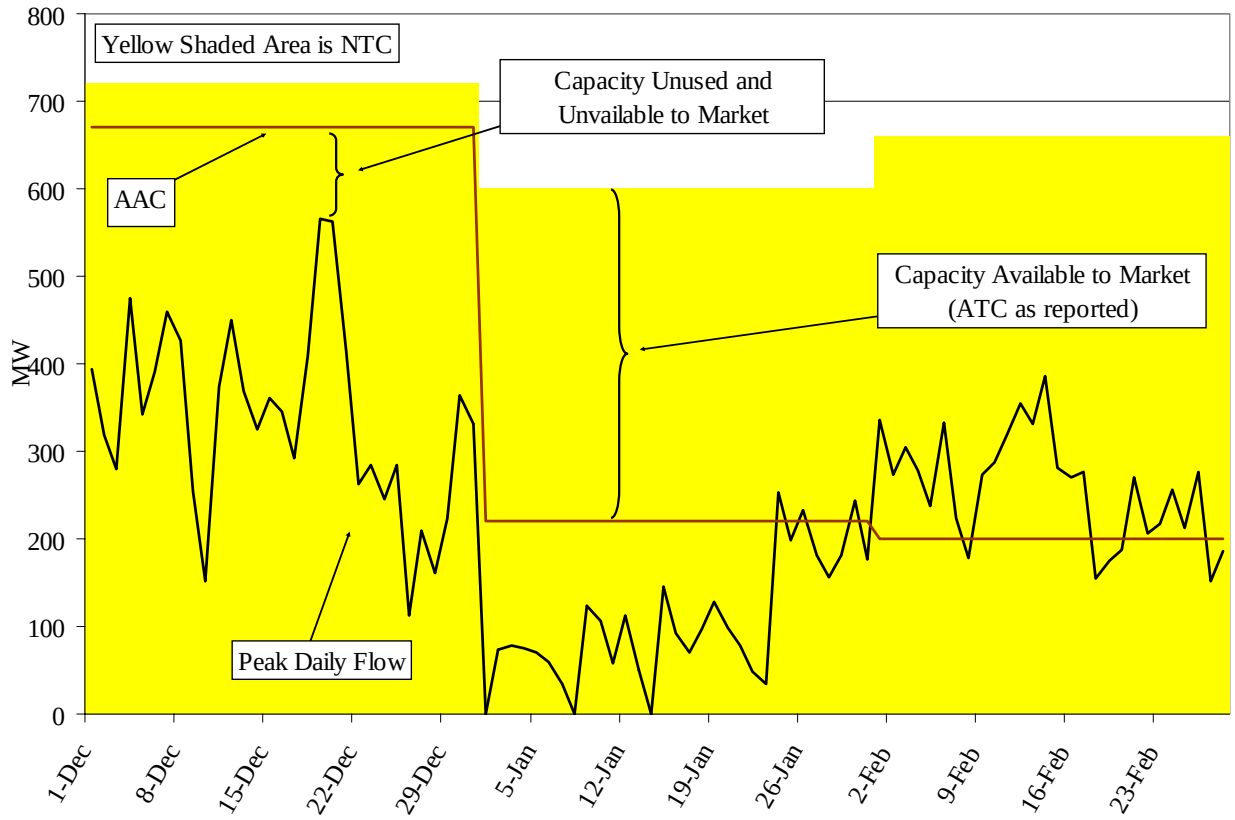
The shaded area indicates the NTC, the amount of capacity on the interconnection estimated to be available (after TRM is subtracted). The difference between NTC and AAC is ATC, as indicated by the bracket. The peak daily flow is shown as a somewhat variable data series. When the peak daily flow is below the AAC, this indicates periods when the actual usage is below what was allocated. It is during these periods when the market could be allocated more capacity by way of a higher ATC value. For this interconnection, line flows exceed the AAC in at least one day during each month, indicating that the AAC and line flows match reasonable well. Since some capacity could have been allocated during the monthly auction, AAC may actually be higher than shown. In fact, depending on how much is allocated in the monthly auction, which began in January on this interconnection, the AAC may exceed the line flows by a significant margin.[7] However, until the data is complete with the inclusion of the auction

[7] We note also that the drop in AAC from December to January was the removal of some allocations from the monthly ATC to the auction.

results, our conclusion is indeterminate at this point. Furthermore, we anticipate collecting loop flow data from the capacity assessment in order to determine the extent to which loop flow may also affect this analysis.

The Bosnia & Herzegovina to Croatia interconnection also indicates flows reasonably consistent with AAC. This is shown in Figure 3.

Figure 3: Power Flow on the Bosnia & Herzegovina to Croatia Interconnection



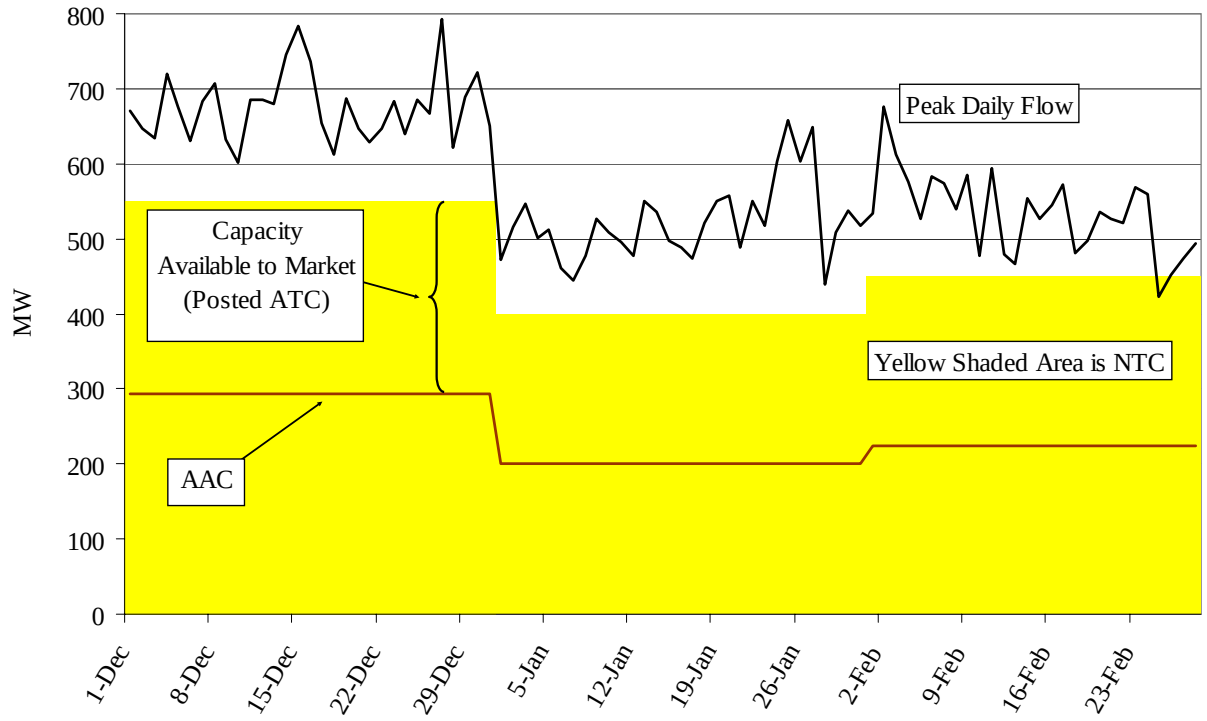
While on many days much of the AAC is not utilized, on the peak day of each month the AAC and line flows are relatively close. We again note that these results are preliminary because actual AAC for January and February likely would be higher if the auction results were reflected in the AAC values.

We also found, on a preliminary basis, that the flows in the opposite direction on this interconnection were reasonably close to AAC as well as flows on Montenegro to Bosnia & Herzegovina interconnection, the Albania to Montenegro interconnection, (in both directions) the

Serbia to Montenegro interconnection (in both directions), the Montenegro to Bosnia & Herzegovina interconnection, and the Serbia to Romania Interconnection. The graphical analyses for these interconnections are shown in Appendix B.

On some interconnections, the power flows were in excess of not only the AAC, but also the NTC. An example of this is the Romania to Serbia interconnection shown in Figure 4.

Figure 4: Power Flows on the Romania to Serbia Interconnection



As the figure shows, the interconnection flow substantially exceeds what was estimated to be the allocated capacity and even exceeds NTC, which is the maximal transfer capability in the regional load-flow model for the interconnection. We sought an explanation for this and were informed that significant loop flows occur from Romania to Serbia. As explained above, the NTC is calculated net of loop flows so that significant loop flows could cause the actual flows to exceed NTC. This situation does not raise concern.

Finally, on some interfaces, there appears to be an over designation of capacity for already-allocated uses that is not used. This occurs on the Serbia to Croatia Interconnection, as shown in Figure 5.

Figure 5: Power Flows on the Serbia to Croatia Interconnection

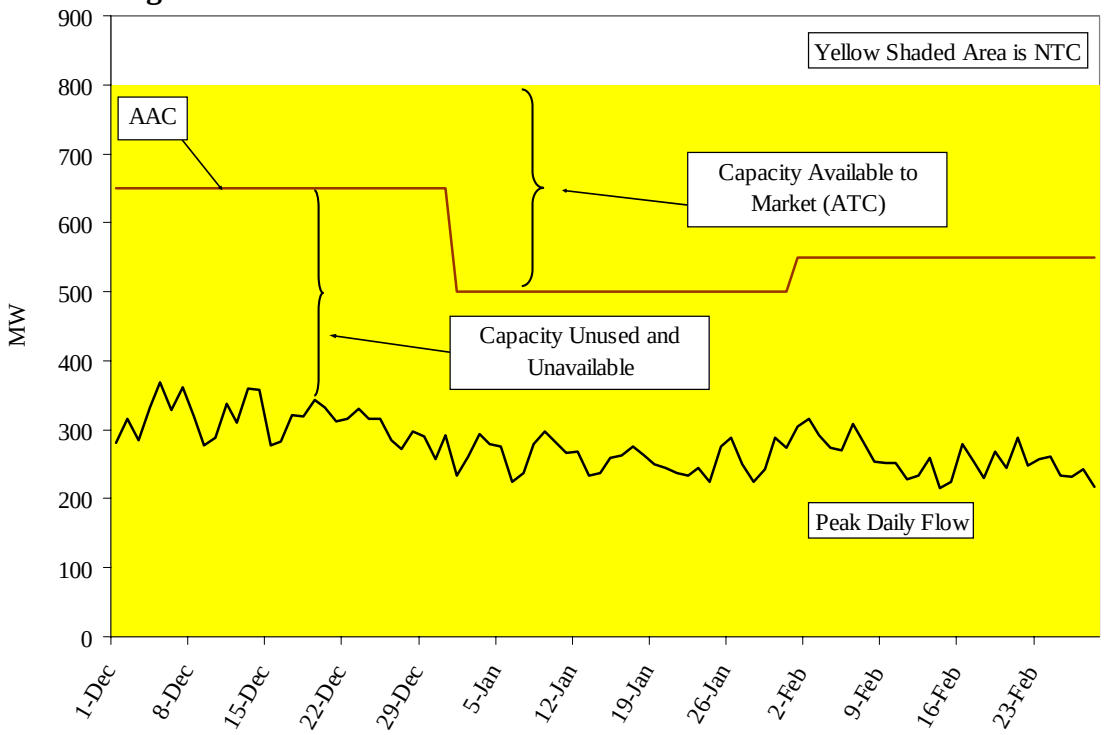
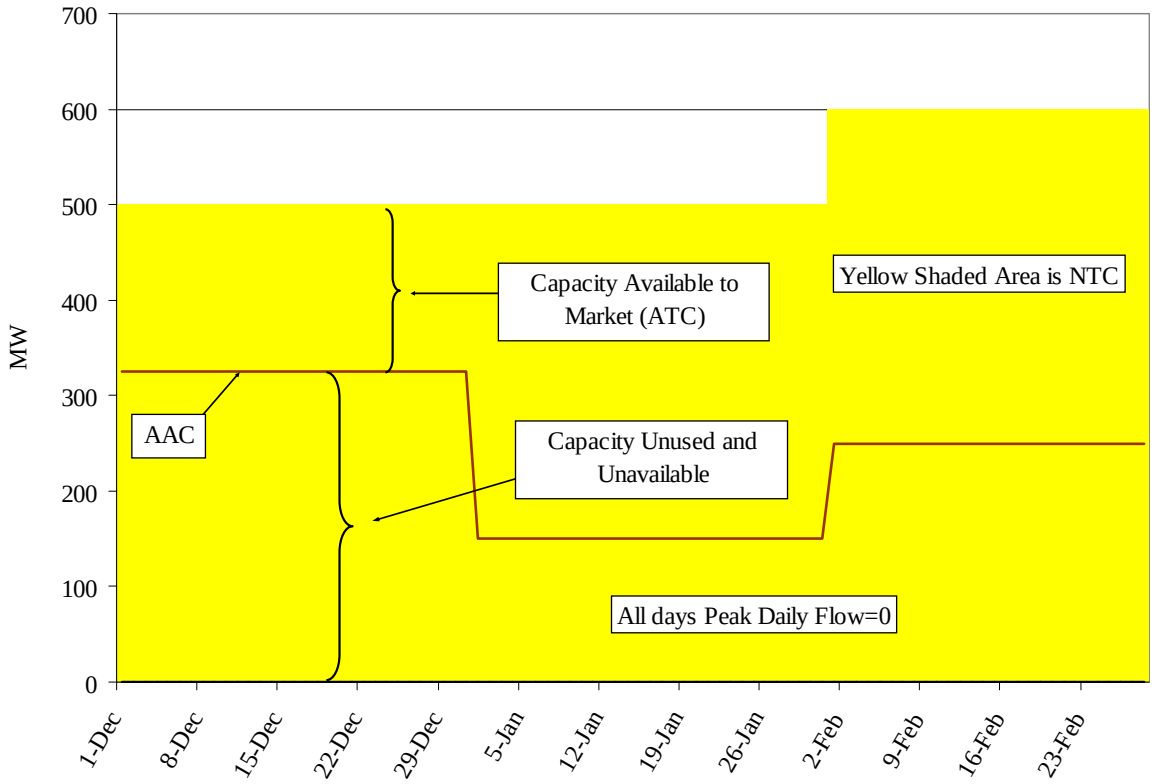


Figure 6: Power Flows on the Croatia to Serbia Interconnection



While it appears too much capacity is set aside on these interconnections, significant amounts ATC exist that is not being used. This indicates the situation does not adversely impact the market and does not raise concerns at this time. It is important to note in the instances of Figure 5 and Figure 6 that AAC may still be higher (and ATC lower) than shown. Loop flow may also play a role in the situation here. If loop flows provide "counter flow" on the interconnections, the reserved capacity on the interconnection may be consistent with the actual transactions but the loop flows reduce the associated power flow.

Finally, as an over all observation, the analysis is incomplete to the extent key data is still needed. In particular, while the analysis seeks to determine whether ATC is maximized, this question is diminished in importance if there is a lack of demand for ATC. Accordingly, as we move to later phases of the Pilot Plan, we may seek additional data to provide a larger context for the analysis.

2. ATC Calculations

ATC in South East Europe is calculated pursuant to procedures set forth by UCTE and endorsed by ETSO. These procedures require operating data and forecasts that are provided by the TSOs. This data can critically affect the estimated level of ATC. In this section, we examine the methods used by the Participants to calculate ATC and identify where monitoring can help ensure accurate and consistent estimates of cross-border capacity.

ATC in South East Europe is calculated on a monthly basis in accordance with guidelines promulgated by ETSO. The estimates of ATC are based on projected uses of the system using a "Base Case" reference power-flow study which simulates the operation of the electricity grid including the flows over the interconnection facilities.

The Base Case is a network model that contains the data meant to depict the electrical situation (load and resources) for the time frame studied. These input data include the thermal ratings of transmission facilities, the output range of generators, and the expected integration of load and resources during the time period studied – i.e., the order in which resources will meet load in each hour of the study. The input data also includes cross-border transactions (base-case exchanges or "BCE").

We have already shown above that there is a potential for ATC to be restricted as the result of parameters of the ATC calculation, i.e., the over estimating of the AAC. There are also a variety of other input data that could affect the ATC calculations. In Phase II we will evaluate the capacity assessment in more detail in order to illuminate areas where the process could improve with market monitoring.

3. Monitoring the Capacity Assessment in Phase II

As the description above indicates, participants must provide critical data in the capacity assessment. In order to better examine whether any particular process or practice systematically distorts ATC calculations, we seek key data used in the capacity assessment.

We seek to monitor five elements from the capacity assessment.

First, we ask each participant to provide the AAC used in the calculation of ATC. Recall that ATC = NTC-AAC. AAC is the allocated portion of the NTC and this determines what is available to the market. We will begin to ask for some of this information starting in April.

Second, we ask each participant for the base case loop flow data so that this factor can be better represented in the line flow analysis.

Third, we ask the participants to provide the merit-order dispatch used to estimate the base case network model. We also ask for the impact of individual generators on the interconnections (commonly known as generation shift factors). We can use this to check the dispatch against alternative dispatch profiles to determine the effect of the dispatch in the network model on ATC.

Fourth, we also ask for a description of the procedure through which market participants can get transmission rights that get categorized as AAC, e.g., grandfathering, auctions, etc.

Finally, we ask for the forecast load assumptions used in the model so that we may compare it to actual load. Over- or under-estimating load can result in distorted usage of the system that can lead to a reduction in the ATC estimates.

B. Wholesale Sales

The primary motivation for market monitoring is to help ensure competitive outcomes. As discussed above, congestion events on the system provide the most likely conditions for an exercise of market power. When periods of transmission congestion arise, a market actor seeking to engage in anticompetitive conduct would execute sales at higher prices in the constrained areas.

We seek to examine sales by market participants to determine whether high prices correlate with periods of transmission congestion. Such an analysis only provides evidence consistent with market power, but is only the first indicator. Further analysis of the circumstances surrounding the sales would be necessary. In the interest of phasing in our monitoring plan we will seek only to understand how the data on sales and purchases is recorded for each participating entity. We will not seek the actual data at this point.

C. Congestion Management

We use congestion management measures as indicators of congestion but they are also the subject of monitoring as well. Primarily we seek to identify measures taken in order to focus on times and locations when the market is most susceptible to market power. However, we may seek to determine whether congestion management measures are applied when they are unnecessary, potentially resulting in market distortions. This latter monitoring will not occur in Phase II but instead will occur, if at all, in later phases after clarifying our intentions in this regard with Participants.

V. GENERATION MODELING

Modeling of regional generation is a critical part of the overall monitoring Pilot Plan. The modeling is an effort to identify the potential for market power. It must be stressed that market modeling does not provide proof of the exercise of market power, as it does not analyze real and observed actions and outcomes. Rather, the modeling can be thought of as an *ex ante* tool which – among other things – attempts to establish (1) what outcomes (in terms of prices, production, trade etc.) an efficiently working market would yield; (2) what separated submarkets could develop in a geographically dispersed region; (3) whether any producer has the incentives and means to exercise its market power (if it exists); and (4) what the overall market outcome could look like if producers freely exercised their market power.

Our modeling will employ market simulations. Market simulations apply economic theory to estimate complex market outcomes under various assumptions about the market participants' behavior and the input parameters entering the model. The economic theory behind these simulation models is that of partial market equilibrium, where the main function of the market is to find the (equilibrium) price at which consumers want to buy exactly as much of the product as the amount that suppliers are willing to sell. Moreover, it is possible to model several interconnected markets simultaneously, which has the added advantage of treating the mutual dependence of market prices in neighbouring markets in a proper way.

In order to outline our suggested approach to model the wholesale generation segment of the SEE region, we will demonstrate the application of partial equilibrium theory using currently

available public data on a very simple example, and describe the implications and extensions of this example which will lead to a more complete modeling effort.

It must be stressed from the outset, that we are thinking in terms of a competitive market simulation, which we consider to be a good starting point, because it describes the most efficient outcome possible and thus provides an ideal benchmark to which actual observations can be compared.

A. Simulation example

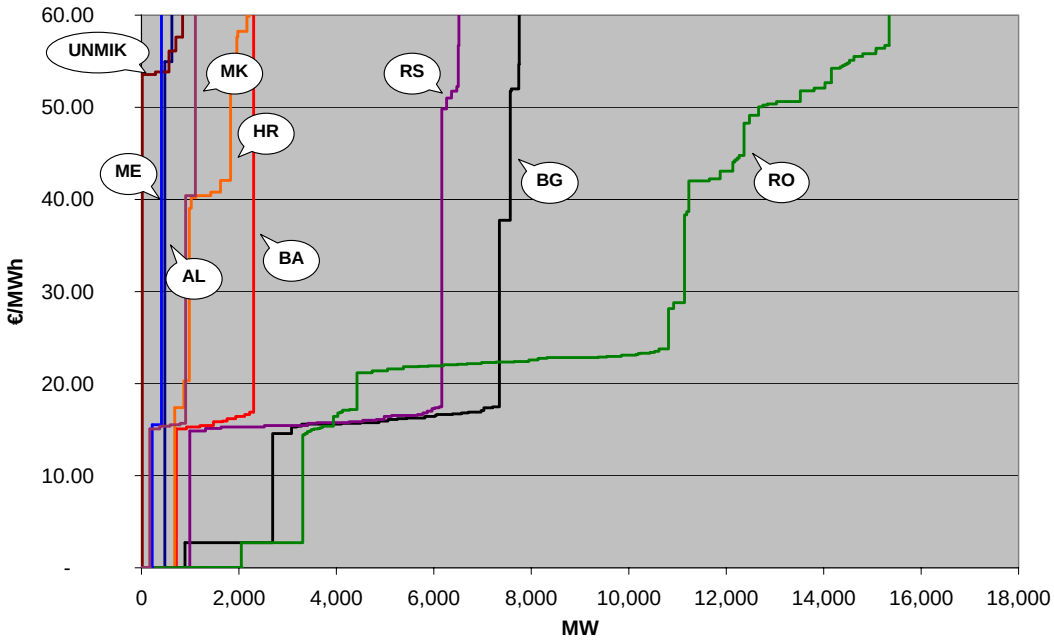
We simulate a single, aggregated (static) regional electricity pool, into which generators offer their capacity at (crudely estimated) marginal costs, whereas demand is completely unresponsive to the price of electricity. These assumptions are more fitting for a very short-run equilibrium, of course. We do not take constraints on trading (transmission) into account at this point.

1. Electricity supply and demand

The marginal costs of electricity generation are identified with the cost of fuel used in the plants, which are likely to make up the largest portion of actual marginal costs. Operating expenditures are not taken into account, and neither are start-up costs or any variation in heat rates at different capacity usage levels. We assume that all plants in the region are capable of generating electricity up to their available capacity (taken to be 90 percent of installed capacity for thermal plants and one-third of installed capacity for hydro generation). We do not take into account reserve requirements and we estimate heat rates based on plant type and average age.

Based on this method, we get the country-by-country estimated merit order curves (supply functions) of the SEE region depicted in Figure 7.

Figure 7: Estimated Merit-Order Dispatch for each Control Area

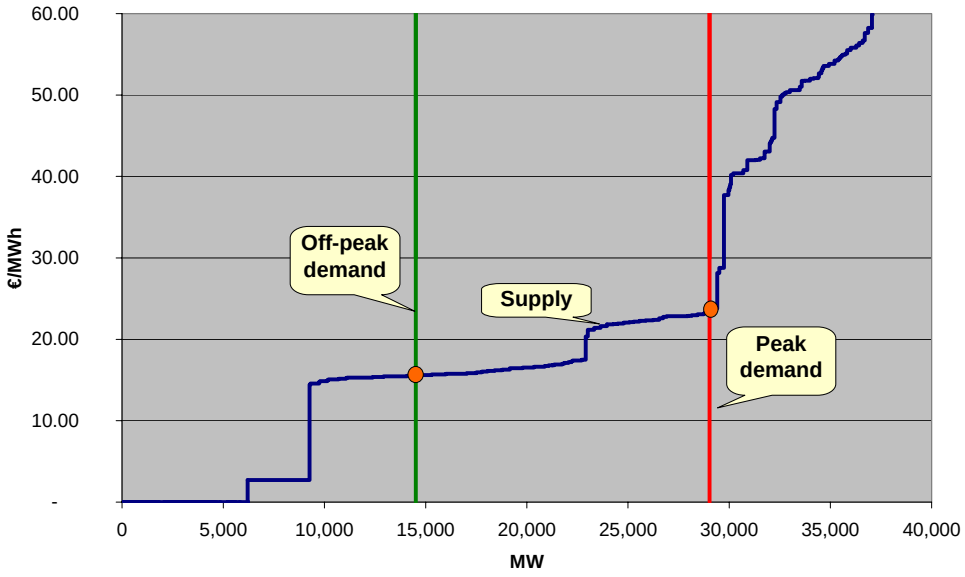


Source: KEMA 2005, own calculations

2. Market equilibrium

Next we incorporate demand into the analysis and aggregate the supply curves of individual control areas into a regional, merit-order supply curve. Regarding the demand for electricity (in a given hour), we consider a peak and an off-peak scenario. Peak loads are derived from observed high consumption periods during January 2006, whereas off-peak demand is taken to be half of the peak load. Our analysis is shown in Figure 8.

Figure 8: Region-Wide Equilibrium



Aggregated demand for the region is simply the sum of the individual control area demands. For simplicity of presentation, we assume that this demand is not dependent on the price of electricity in the short run.

The figure shows graphically the determination of a regional market equilibrium at a price of 23.39 €/MWh in peak and 15.61 €/MWh in off-peak periods. The corresponding total generation is 29,030 MWh (peak) and 14,515 MWh (off-peak). All power plants whose marginal cost is below the market clearing price operate at full capacity, whereas the ones with cost above the price do not produce at all. Marginal generators provide the difference between total demand and the production of the infra-marginal units.

Obviously, this example completely disregards any transmission constraints. Its main advantage is a simple demonstration of the market equilibrium. In the inception report on market monitoring and market simulations, we actually show that market equilibrium in the peak scenario would produce trade patterns which are infeasible in reality, implying that during high demand scenarios we cannot consider the SEE region to constitute a single market area even under fully liberalized market conditions.[8]

[8] The off-peak scenario yields trade patterns which do not violate any NTC constraints. Thus, the simulation suggests that the SEE market could in fact be integrated during low demand hours.

By and large, our very preliminary results suggest that the SEE region is likely to fall into three separate sub-markets in the peak load scenario: a large Eastern exporting region comprised of Romania and Bulgaria, the strong Western importer of Croatia, and the transit markets in between.

In the model, therefore, we need to take into account trading constraints explicitly and allow for the evolution of different market prices in different sub-regions, if these constraints are not to be violated. Different ways of doing so are described in the modeling inception report.

B. Extensions

Besides the necessary inclusion of transmission constraints, the competitive market simulation could be extended along the following lines:

- include several demand scenarios with estimated (guessed) price elasticity parameters
- include different supply scenarios as well with regard to weather conditions (hydro generation is relatively important in the region)
- build a more realistic model of marginal generation costs (without actually including a time dimension, to keep the model at a tractable level)
- take account of long-term power purchase agreements and other must-run obligations, if these do not correspond to the merit order
- account for reserve and balancing requirements
- include more information on outages, both planned and unplanned
- enlarge the simulated region to include neighbouring countries (at least Slovenia, Hungary and Greece), or at least account for the net export/import position of the SEE region vis-à-vis its neighbours

VI. SUMMARY OF SCOPE FOR PHASE II

Beginning with the publication of this report in April, we will begin Phase II of the Pilot Plan. Phase II is the advanced monitoring of the cross-border capacity market and the initial phase of the of the Wholesale generation market monitoring.

We have been satisfied that the data collected in Phase I have been useful in our monitoring activities and we propose to continue to request this data on a monthly basis throughout Phase II. In addition, we propose a set of data requests and a further analysis of these data in Phase II. We seek to expand both the data for monitoring the cross-border transmission capacity market and the data for monitoring the wholesale generation market.

As explained above, for the cross-border capacity market, we seek additional data and analyses on the capacity assessment (NTC calculations), congestion management, and sales and purchases.

The capacity assessment is the process for establishing the cross-border capacity available to the market (ATC). The estimates can be very sensitive to the underlying assumptions in the base case regional power flow model. Power flow models depend critically on the assumptions regarding integration of load and resources, especially how resources are dispatched to meet anticipated load and how interconnections are assigned capacity for set asides. We have designed data requests to elicit this information.

We also seek to refine the measurement of system congestion by requesting information about congestion management procedures, especially how they relate to curtailments. When a curtailment occurs, this is an indicator of extreme or unanticipated network congestion. We are interested in monitoring the frequency and location of any such event in order to focus monitoring attention when and where it is needed.

Finally, as indicated in previous sections, sales and purchase activity on the system is a critical component of the market monitoring. Primarily, the analysis of sales and purchases data permits a closer evaluation of the market circumstances at times when the market is most susceptible to market power, i.e., when congestion arises. We propose to initiate collection of this data. Our

first step in this process is to gain more familiarity with the format, location, and content of the data with the intention of developing data requests in latter phases of the Pilot Plan.

In order to support development of the generation simulation, we have expanded our request associated with generation data to include more operating information.

Appendix A

Data Request 1 for

Phase I

of the South East Europe Market Monitoring Pilot Plan

Issued to Participant TSOs on January 12, 2007 (slightly revised versions sent February and March).

- ***Request 1-1***
  Please provide actual load for the TSO control area for each hour for the month of December 2006.

- ***Request 1-2***
  Please provide the actual hourly power flows over all external interconnection for the month of December, 2006. *Note: For purpose of this data request, the term "external interconnection" means each point in the TSO's transmission network that ties in to the system of an adjacent control area and for which cross-border transmission capacity is calculated and posted. The data should be provided on an individual external interconnection basis, i.e., TSOs with multiple external interconnections should provide separate data for each external interconnection.*

- ***Request 1-3***
  For each generating unit in the TSOs control area, please provide
  1. Unit name;
  2. Unit type, (for example hydro, steam turbine (coal); steam turbine (oil), internal combustion (gas); combined-cycle);
  3. Unit manufacturer's (nameplate) capacity;
  4. Unit rated capacity for December 2006 (i.e., maximum capacity available for dispatch during the month);
  5. Outage derating for December 2006 (i.e., indicate whether and how much the unit was derated as a result of planned or unplanned outages for the month).

Appendix B

This Appendix presents the remaining Interconnection flow analysis not presented in Section IV.A.1.

Figure B- I: Power Flows on the Albania to Montenegro Interconnection

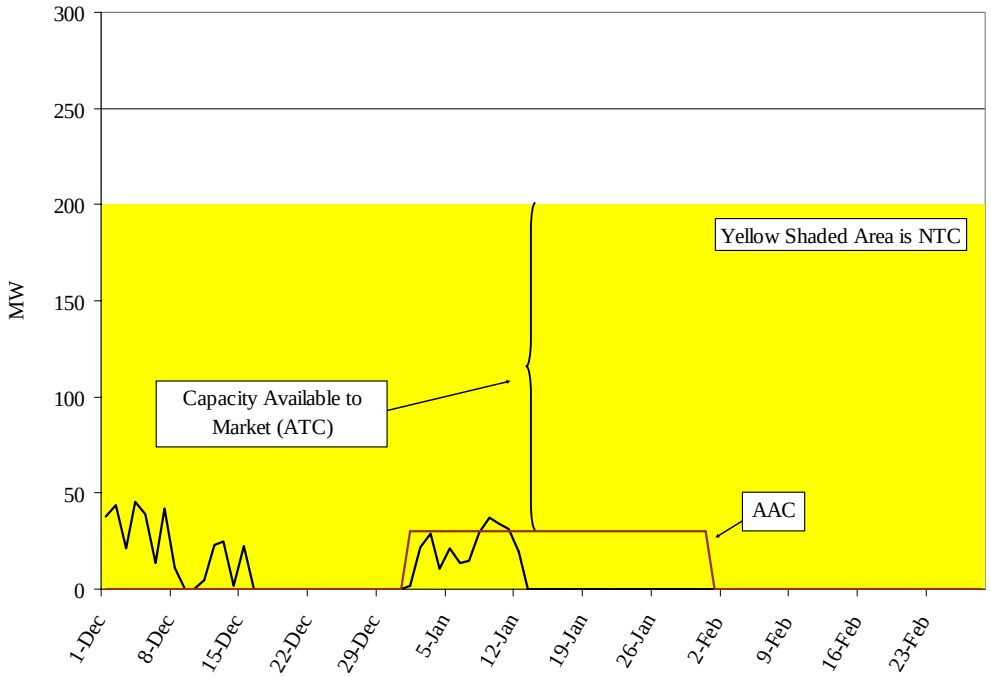


Figure B- II: Power Flows on the Serbia to Montenegro Interconnection

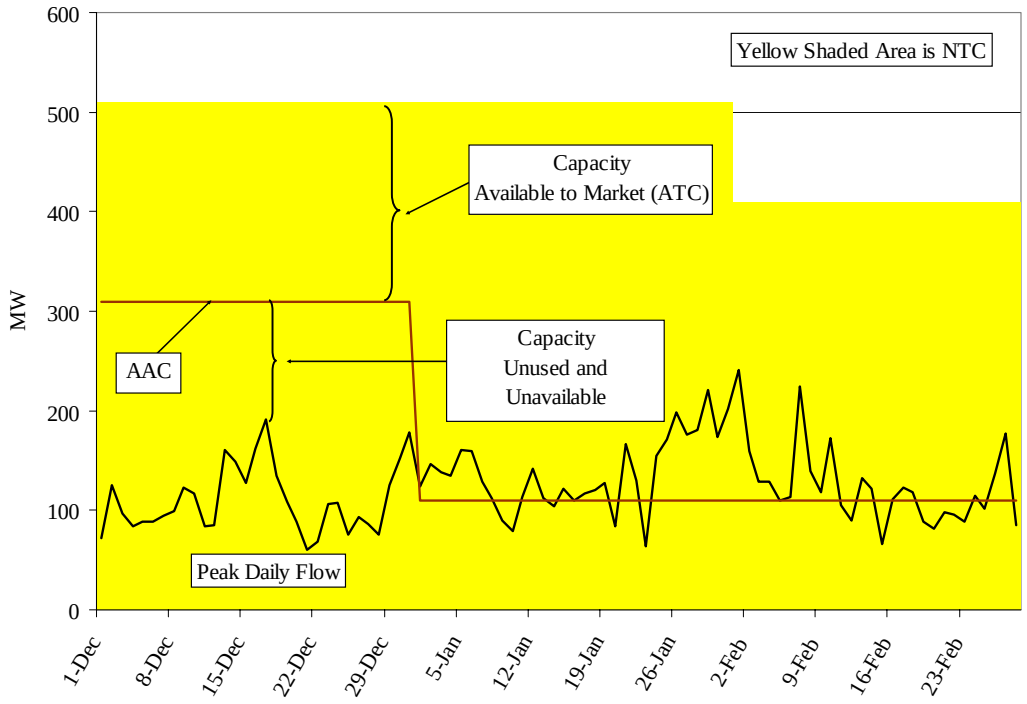


Figure B- III: Power Flows on Montenegro to Albania Interconnection

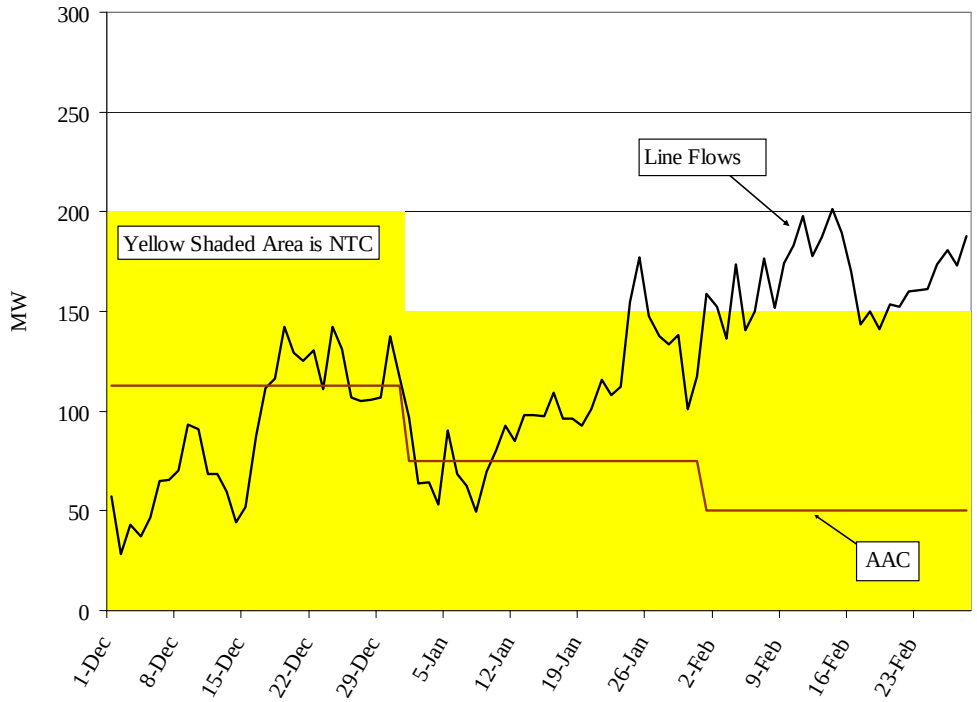


Figure B- IV: Power Flows on the Croatia to Bosnia & Herzegovina Interconnection

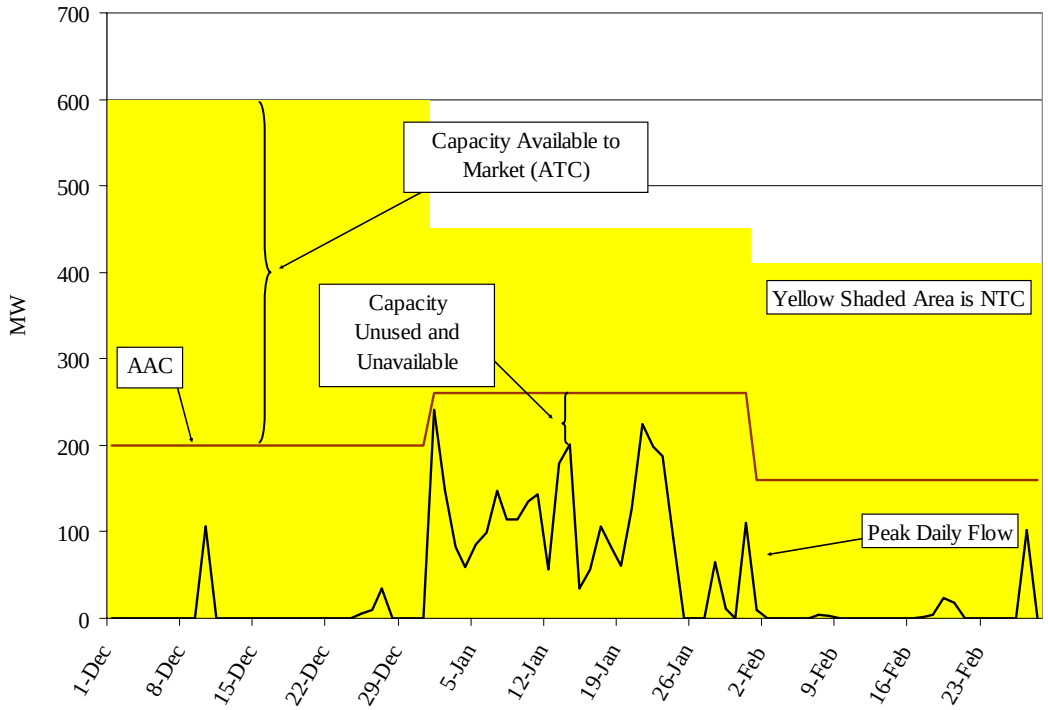


Figure B- V: Power Flows on Montenegro to Bosnia & Herzegovina Interconnection

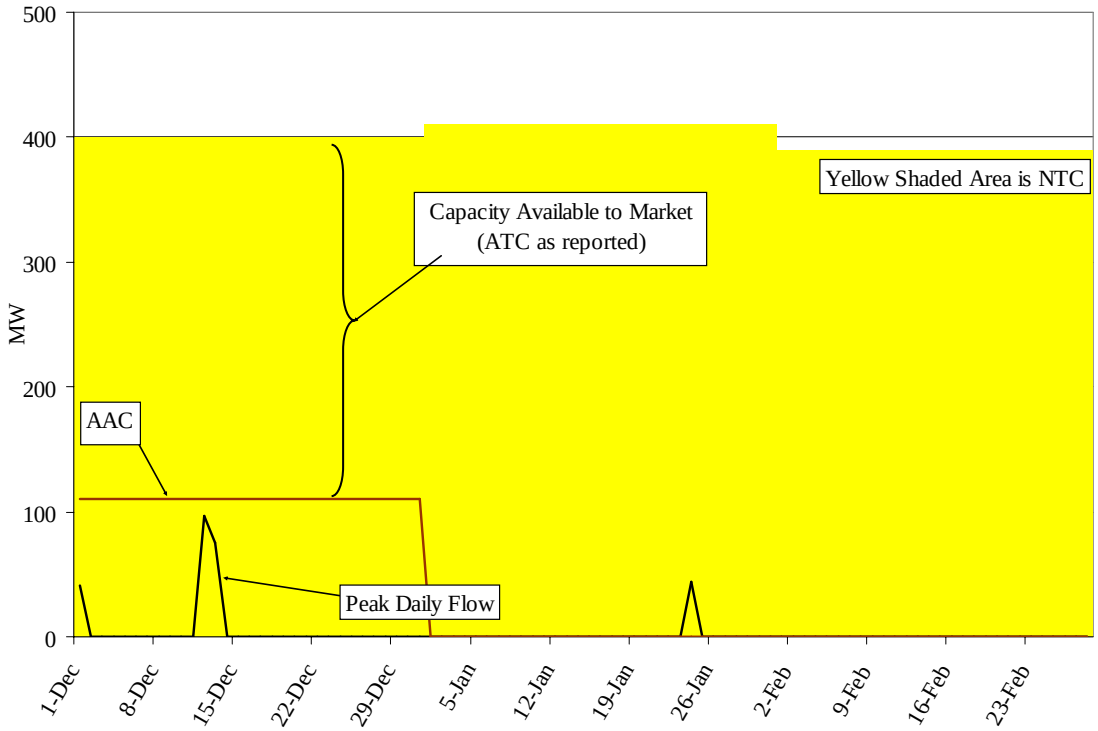


Figure B- VI: Power Flows on Serbia to Bosnia & Herzegovina Interconnection

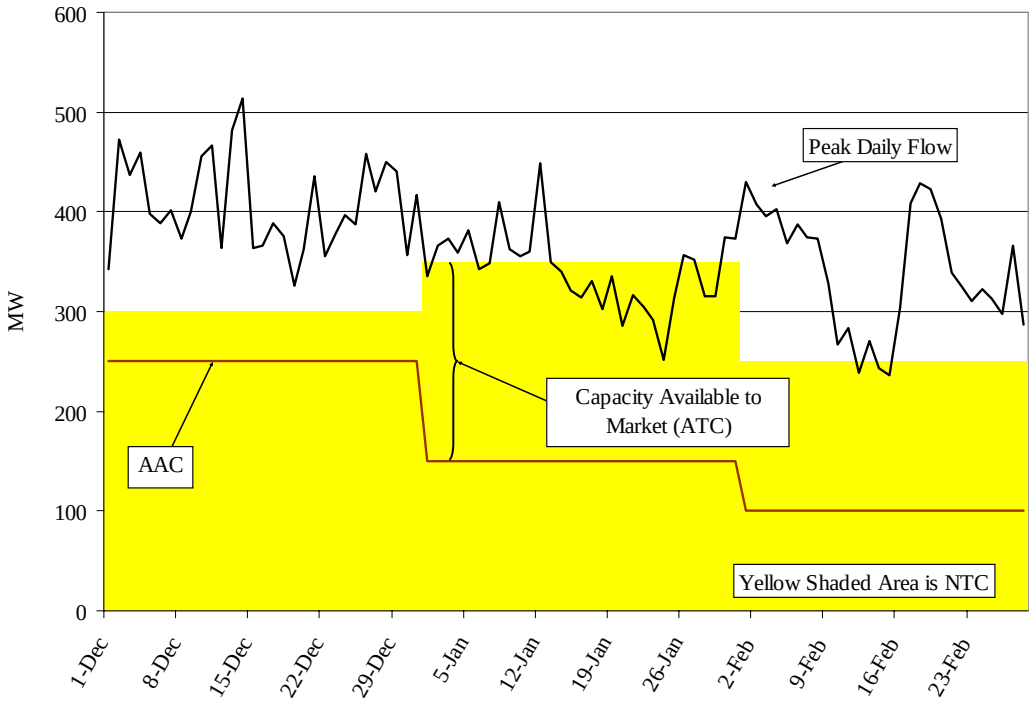


Figure B- VII: Power Flows on the Montenegro to Serbia Interconnection

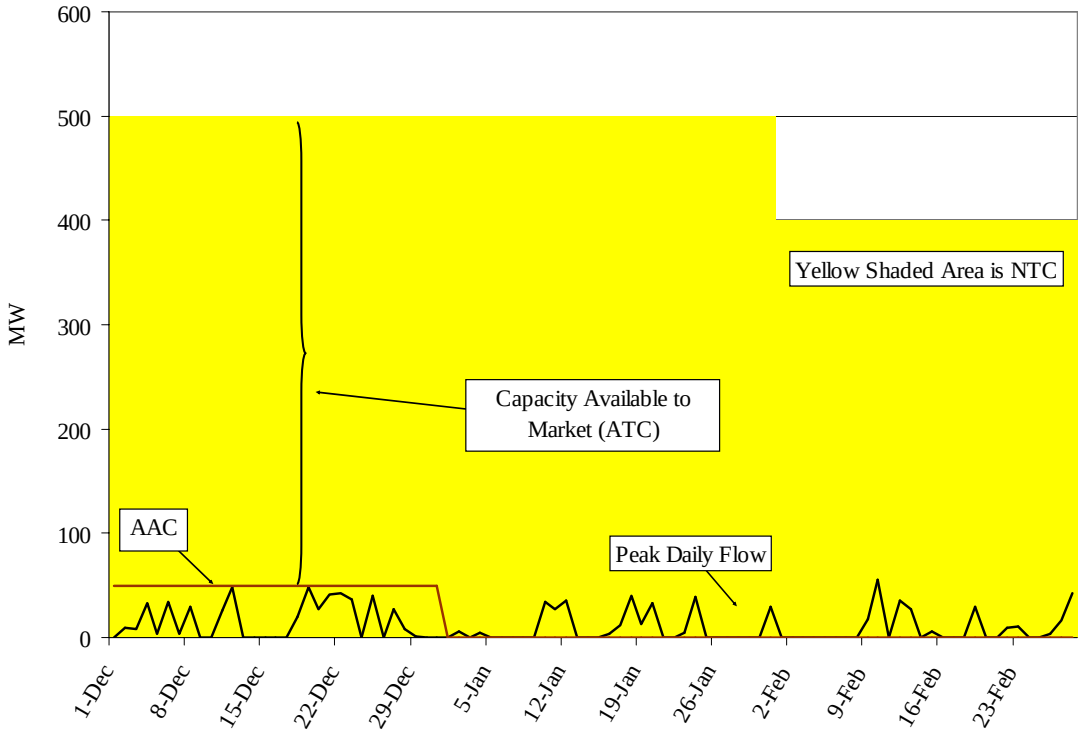


Figure B-VIII: Power Flows on the Serbia-Macedonia Interconnection

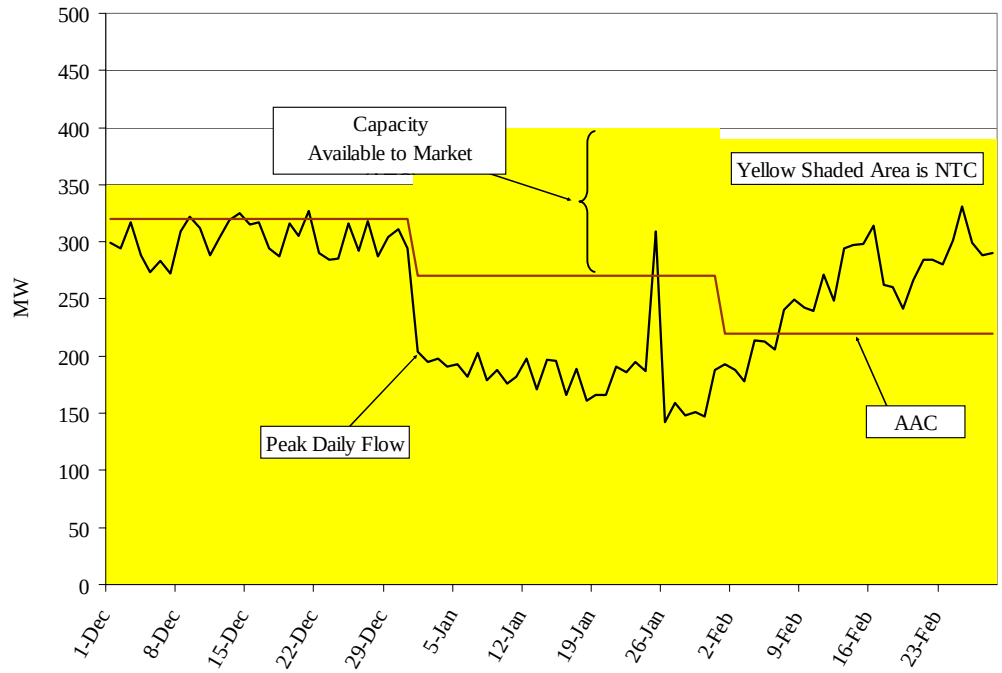
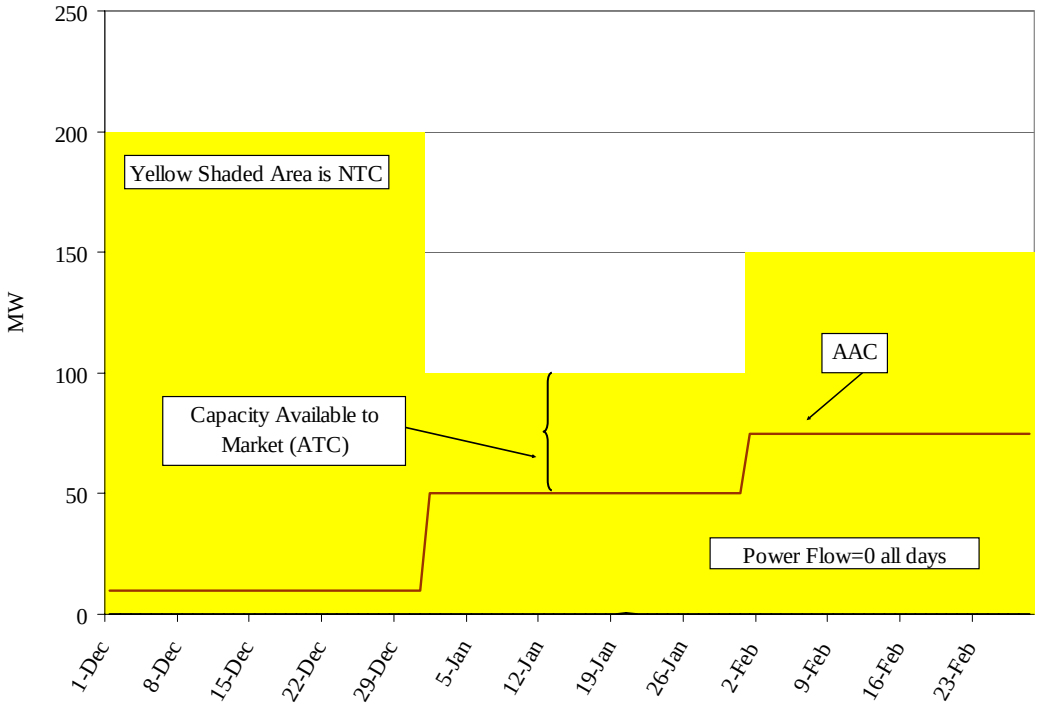


Figure B-IX: Power Flows on the Serbia-Romania Interconnection



Appendix C

Data Request 2 for

Phase II

of the South East Europe Market Monitoring Pilot Plan

Note: For purpose of this data request, the term "interconnection" means each point in the TSO's transmission network that ties in to the system of an adjacent control area and for which cross-border transmission capacity is calculated and posted. The data should be provided on an individual external interconnection basis, i.e., TSOs with multiple external interconnections should provide separate data for each external interconnection. A "cross-border transaction" is one that utilizes an interconnection.

- ***Request 2-1***

<u>Purpose</u>: This data request is to identify instances of congestion on the network and use this information to focus on locations and periods when the market is most vulnerable to the exercise of market power. There is currently no intention to investigate the legitimacy of any actions identified in this request.

(a) Please provide a description of Congestion Management procedures (aside from allocation of monthly or daily transmission capacity) that could result in the full or partial curtailment of a cross-border transaction.

(b) Indicate whether any curtailment associated with the measures in (a) occurred during the month of April 2007.

(c) Indicate the date on which the event in (b) occurred and on which interconnection.

- ***Request 2-2***

<u>Purpose</u>: We wish to collect this information to more closely monitor the capacity the capacity assessment and capacity allocation processes. To the extent possible, we would like to check the accuracy of the various inputs.

With respect to calculating NTC on each interconnection:

Please indicate the peak parallel flow on each interconnection in UCTE reference base case for April 2007;

Please provide the Base Case exchange on each interconnection in the UCTE reference base case for April 2007;

Please provide the forecast load for the control area in the UCTE reference base case for April 2007;

Please provide the merit-order dispatch used in the UCTE reference base case for April 2007; (Merit-order dispatch means the order in which generators are dispatched in the network model to meet each increment of load (cost-based dispatch order))

For each generating unit in the TSO control area, please provide the generation shift factors for each interconnection in the UCTE reference base case for April 2007. *The generation shift factor indicates the percentage of an incremental MW of output from a unit that will flow on the interconnection.*

Please provide a description of the procedure through which market participants can get transmission rights by which they fall into the "AAC right owner" category, e.g. grandfathering, auctions, etc.

Please indicate whether AAC rights are tradable or otherwise transferable under the procedures which guide any such process.

- ***Request 2-3***

<u>Purpose</u>: We are requesting this data in order to devise a strategy to collect actual sales and purchases data. In light of claims of confidentiality, a better understanding of the nature of the data available and who is in possession of the data may assist the TSOs in making the data available while at the same time maintaining confidentiality.

Please describe the types of bilateral contract sales that can occur in the control area; in responding, please indicate the nature of the parties, e.g., generator, marketer; supplier (local distribution company), end-user (retail customer);

Please describe the process for recording bilateral sales contracts on the network.

Please indicate whether prices are recorded for these contracts.

Please identify the entity in possession of records of bilateral contracts.

If these records are in possession of the TSO, please indicate the circumstances under which they could be made available for purpose of market monitoring.

- ***Request 2-4***

<u>Purpose</u>: The generation modeling aspect of the monitoring plan will be initiated in Phase II. This data requested will be used to create a regional generation market model as discussed in Section V of this report.

For each generating unit in the TSOs control area, please provide

1. Unit name;
2. Unit type, (for example hydro, steam turbine (coal); steam turbine (oil), internal combustion (gas); combined-cycle);
3. Unit manufacturer's (nameplate) capacity;
4. Unit rated capacity for April 2006 (i.e., maximum capacity available for dispatch during the month);
5. Unit (average) heatrate
6. Outage derating for April 2006 (i.e., indicate whether and how much the unit was derated as a result of planned or unplanned outages for the

month).

7. Start-up costs
8. Average cost of Fuel
9. Long-term contracted capacity, other must-run obligations, Reserve, and balancing requirements