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MARKET POWER AND PRIVATIZATION IN THE GEORGIA ELECTRIC SECTOR

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MARKET POWER AND PRIVATIZATION IN THE GEORGIA POWER SECTOR

The Government of Georgia has elected to bundle certain generation facilities with distribution facilities in offering electric assets for sale to strategic investors. This paper evaluates the proposed bundling in light of concerns about market power.

1. Market Power in Georgia

The proposal to combine generation facilities with distribution companies in a single package to facilitate the privatization of less attractive electricity industry assets does not pose a threat to a competitive Georgian electricity market. As currently configured, the Georgian electricity market is not capable of sustaining a competitive market, and will not be capable of workable competition for the foreseeable future.

In order to have a competitive electric market, there must be a sufficient number of generators and/or the possibility of entry, either through greenfield facilities or transmission from other countries. Because significant sunk costs are associated with the building of generation facilities, the only possible means for the Georgian electric market to imitate Baumol's "Contestable Market" would be through the existence of sufficient transmission capacity from a number of countries. In such a case, if the number of generators in Georgia were insufficient to provide a competitive market, the potential for the importation of electricity would discipline domestic producers. Georgia, however, lacks sufficient points of interconnection or transmission capability with foreign generators to form a competitive market.

When analyzing market power in electricity, it is important to note the existence of "submarkets," each of which must be examined. We may postulate numerous electricity submarkets, as many as one for each hour, but a practical analysis will focus on segmenting the market by broad categories of demand such as base load, shoulder, and peak load, and possibly by season, winter, spring/fall and summer. In this case the extent of market power in various market segments should be measured by the sum of the potential revenue which may be transferred to producers relative to a purely competitive market. Thus, a period with significant market power, but with little consumption, may not warrant concern because the total economic impact on consumers, averaged over the year, would be minimal. Therefore, the most important market segments will be those with both significant market power and a sizeable fraction of total consumption.

The key period to be examined in Georgia is the winter period, which runs from approximately November through March. Currently, Georgia electricity demand peaks during this period due to the extensive use of electric heaters. Over time, as natural gas supply is resumed to Tblisi, and incomes rise, resulting in increased purchases of air conditioners, the demand profile should shift to winter and summer peaks of similar magnitude, with two offpeak periods in the spring and fall. The Georgians do not, however, collect monthly and seasonal peak or consumption data at this time.

Hydroelectric generation tends to decline throughout the winter period, as the change from rain to snow in the mountains reduces the flow to the run-of-river and daily regulating hydroelectric facilities, and the reservoirs of the storage hydroelectric plants are depleted. Consequently, thermal generation and imported power play an increasingly important role during the winter demand period. Run-of-river plants peak during the summer, while the thermal generation is shut down because hydropower is sufficient to cover domestic demand as well as provide power for export.

Annual regulating hydroelectric plants account for about half of all Georgian electricity supplies, with the vast majority produced by the Inguri plant and the associated Vardnili hydroelectric cascade. Run-of-river accounts for another twenty percent of generation, with the rest produced by Gardabani, the thermal plant, or obtained through imports. During the winter months, Gardabani produces a larger share of generation, up to forty percent, but hydropower still predominates.

The run-of-river hydropower can be considered "must-run," because the output is determined only by streamflow. The low cost and must run nature of run-of-river hydroelectric power makes it the primary source of base load power in Georgia. So even though there are numerous run-of-river facilities, they act similar to a competitive fringe, except that they produce their maximum output at all times regardless of price.[1] Therefore, when analyzing the market, the output of these facilities should be subtracted to provide the residual demand curve faced by generating facilities which can control their output.

Once the run-of-river facilities are removed from the market analysis, it becomes clear how little competition can exist in the Georgian electricity market. The run-of-river facilities account for 255 megawatts of capacity. There are five annual regulating hydroelectric facilities, one daily regulating facility, and Gardabani thermal power plant. However, the Inguri/Vardnili complex has a capacity of 970 megawatts, compared to 250 megawatts for the other annual

[1] In the long run, these run-of-river plants can change their level of output through investments in rehabilitation and expansion of generation capacity if streamflow permits additional production. It is conceivable that if one entity owned the majority of run-of-river hydroelectric facilities, then output could be withheld through scheduling of normal maintenance at opportune times. However, the low marginal costs associated with these plants suggests that normally they will operate at maximum capacity, since it would take a substantial escalation in price to compensate for lost net income from withholding output which could not be recovered at a later time.

hydroelectric plants and 64 megawatts for the one daily regulating facility. Gardabani currently has a generation capacity of around 650-700 megawatts. Theoretically, there is 1,200 MW of transmission capacity to Russia and another 645 megawatts to other potential import sources. However, the intertie has been limited to 200 MW for the last several years, and this limitation is likely to remain for an indefinite period extending beyond this winter.

A standard measure of the level of concentration in a market is the Herfindahl-Hirschman Index (HHI), which is calculated by squaring the market share of each firm (or discrete soource of generation in this case), expressed as a percentage of total capacity, and summing over all firms in the relevant market. At first glance, the HHI for the Georgian electric sector would seem to suggest a fairly competitive market. Under the Department of Justice merger guidelines, an HHI between 1000 and 1800 indicates a moderately concentrated market. If you eliminate the run-of-river, the market becomes less competitive, as the HHI rises to a level that indicates a highly concentrated market. However, if you eliminate imports as a constraint on the market, electricity generation in Georgia becomes highly concentrated. These calculations do not take into account the decline in hydroelectric capacity in the winter months, which increases the level of concentration in the generation market during the period of maximum electricity demand.

Georgian Generating Capacity

Type of Generation Plant	Capacity (MW)
Run-of-river	382
Daily regulating	71
Annual regulation	1,324
Thermal	700
CHP	14
Russia	1,200
Other Imports	645
Total	4,336

HHI Calculations

Type of Generation Plant	All Units	Excluding Run-of-river	Excluding Imports and Run-of-river
Run-of-river	13	-	-
Daily regulating	3	3	11
Annual regulation	523	629	2,210
Thermal & CHP	81	97	341
Russia	766	921	-
Other Imports	85	102	-
Total	1.469	1,752	2,563

Market power in the Georgian electricity market is far worse than the above calculations indicate. Market power is defined as the ability of a firm, or group of firms acting in concert, to raise price above competitive levels. Generating units fall in three broad categories with regard to marginal costs. The hydroelectric plants have the lowest costs, with estimated variable costs as low as 0.1 - 0.3 cents per kWh. The Gardabani thermal plant produces electricity at a variable cost ranging between 2.5-3 cents per kWh. Imports are available at a price ranging from 2-7 cents, depending on the time of year, the source, and negotiated terms.

This range of costs suggests that Gardabani capacity places a ceiling on hydroelectric prices that far exceeds costs during periods of low demand. Since Inguri is the swing producer during these periods, the operator of this unit will be able to set the market price. During the periods when demand exceeds the capacity of the hydroelectric facilities, the only restraint on Gardabani as a price setter in the market is imported electricity. Armenian electricity demand also peaks during the winter period, so Russia becomes the primary source of significant electricity imports during the peak months. Thus, Russia and Gardabani can act as a duopoly, treating the hydroelectric plants as a competitive fringe, and setting output and price to maximize revenue given the output of the hydroelectric plants. This scenario is more complicated than presented. The regulating hydroelectric units are also used for peak power, due to their ability to ramp up and down quickly, and the absence of combustion turbines. Therefore, the market will be dominated by the Inguri hydroelectric facility and the Gardabani thermal facility. Given the limited potential for electricity generation competition, we recommend continued regulation of generation prices for Georgia.

2. The Distribution/Generation Privatization Clusters

As part of the privatization of Georgian generation and distribution assets, the Kutaisi distribution company was to be combined with five hydroelectric generating facilities: Laujanuri, Shaori, Tkilbuki, Rioni, and Gutami I and II. Laujanuri is a daily regulating facility, Tkilbuki and Shaori are annual regulating hydroelectric plants, while Rioni and Gutami are run-of-river hydroelectric facilities. The Kutaisi distribution company has sales of around 200 GWh/year, or a little over 4 percent of Georgian annual demand of 4,500 Gwh.

	Effective Capacity	1996 Generation	1997 Generation	1998 Generation
Laujanuri	71.0	88.0	155.0	154.0
Shaori	30.0	78.3	132.0	100.6
Tkilbuki	44.0	88.0	155.0	154.0
Rioni	48.0	280.2	284.0	182.0
Gutami	66.8	227.8	217.0	321.5
Total	259.8	762.3	943.0	912.1

Similarly, the Rustavi distribution company was to be combined for sale with the Khrami hydroelectric plants and Tbilresi (Gardabani) thermal plant. Rustavi distribution company has sales of 77 GWh/year, less than 2 percent of Georgian electricity demand. Because the Khrami hydroelectric complex is the second largest regulating hydroelectric plant, and Gardabani is the only major thermal plant in the country, bundling these two generation facilities raises serious market power questions, irrespective of the combination of generation with distribution.

	Effective Capacity	1996 Generation	1997 Generation	1998 Generation
Khrami I & II	150.0	442.7	528.0	440.0
Gardabani	700.0	1,087.4	1,109.8	1,540.0
Total	850.0	1,530.1	1,637.8	1,980.0

The bundling of generation with distribution assets presents two separate: 1) bundling of sufficient generation units to provide a company with significant market power; 2) bundling of generation and distribution assets.

The first concern, the concentration of the ownership of generation facilities in the hands of a small number of companies, would be a problem if a competitive generation market was considered feasible in the near future. In such a case, allowing a company to own a sizeable share of generation would provide it with the potential to exercise market power. Thus, given a competitive market, ownership of a significant portion of generation capacity by one firm or a small group of firms should be discouraged.

A competitive power market will not, however, be feasible in Georgia without a significant increase in interconnections and transactions with the surrounding countries of Turkey, Azerbaijan, Armenia and Russia. If there were sufficient transmission capacity, and peak loads had different temporal and seasonal dimensions, an active interregional electricity market could be developed. Such a market would not eliminate market power concerns, but it would raise the ante for a company to possess and exploit market power. If there were numerous thermal and hydroelectric plants which could potential supply customers in Georgia, then control of Gardabani or Inguri would be insufficient to provide their owner with substantial market power in the regional electric market. Unfortunately, it is unlikely that a true interregional electricity market will be attainable in the near future. Accordingly, the bundling of generating units appears not to present competition concerns under current circumstances.

The second concern, the combination of ownership of generation and distribution, could be a problem both under regulation and competition. Under a regulatory regime, the concern is whether the combination of generation and distribution would allow the company to conceal self-serving transactions between its subsidiaries. In a competitive market, the company might try to cross-subsidize entry in competitive power markets through profits from sales to its regulated subsidiaries. This strategy, however, requires that the regulator allow such pricing to regulated distribution subsidiaries and the company can recoup lost profits used to subsidize power sales at some future point in time.

Given the necessity for regulation of the price of electricity supplies to distribution companies, there is a problem of monitoring the utility "holding companies" created by bundling generation and distribution companies to prevent self-serving transactions. This problem is a subset of the more general requirement that the GNERC monitor and audit the companies under its authority. In a country with few trained accountants, the absence of an active Securities and Exchange Commission which vigorously polices financial reporting, and the threat of shareholder and derivative suits, there are few incentives for accurate financial accounting. The GNERC lacks the necessary financial and technical resources closely to monitor the cost accounting, reporting and expenditures of the companies that it regulates, and there are no other regulatory authorities upon whose efforts the GNERC can rely.

These circumstances suggest that ownership of electricity facilities by Western firms which are accountable for their financial practices in their home countries, and who routinely utilize modern accounting methods with trained personnel, will reduce the regulatory burden faced by the GNERC. In turn, the inclusion of predetermined long-term tariffs and investment schedules as part of the auction process simplifies the regulatory process by limiting the GNERC's decision to approval of the proposed tariff as part of the process of privatization. Once the tariff has been accepted, GNERC no longer needs to collect and verify financial data for the regulated company for the life of the tariff agreement.

At the same time, the long-term tariff eliminates the temptation for self-dealing, as the price to be received for electricity from generators is fixed, regardless of the company's cost allocation. The distribution subsidiary of the foreign company will be presented with the market price of electricity, and the distribution tariff for the distribution company will have been set as part of the privatization process.

There is a question of repercussions at the end of the long-term tariff. Given that the regulatory capabilities of the GNERC should improve over time as staff and commissioners gain experience, there is no reason to think that the Commission should have difficulties in negotiating either a new set of tariffs or a transition to a competitive generation market as needed in the future.

Foreign investors are faced with a public goods problem when it comes to investing in generation or distribution assets. Owners of generation want to ensure that sufficient funds are collected by distribution companies to pay generators. Owners of distribution companies desire that generators have sufficient resources to buy fuel and finance repairs so as to supply sufficient power to the electricity transmission system to meet distribution demand. Currently, the combination of nonpayment and leakage of funds has limited the funds received by generators to a small fraction of the tariff price for electricity generated. While the institution of the new payment system under the market rules should reduce losses, as long as distribution companies are government-owned, they lack the political will and resources to provide full payment for electricity received. So foreign investors gain from the investment of other foreign investors in generation and distribution assets.

The foreign investor would like to raise money through ownership of distribution and pay it directly to the generation units it also owns, to ensure payment for electricity generated. While this behavior will be restricted by the Commission's, and the Market Rules', restraints on direct contracting, dual ownership may still provide benefits to the investor. If the Market Rules are enforced, distribution companies will be limited to the amount of electricity for which they have made payments. In this case, the investor, by enforcing collections and financing shortfalls, can provide 24-hour power to its distribution customers, while receiving full payment for the electricity generated by the facilities it owns, without direct contracts between the distribution company and the generating facility. Failure by distribution companies to pay for power will free generation capacity to sell power for export, which will also provide a reliable source of funding.

This may present political problems unless a majority of the country's distribution systems are owned by investors. If only a few distribution companies are owned by investors, there will be pockets of the country where 24 hour power and strict collections are the rule, and the rest of the country will receive less electricity than currently supplied, since the current implicit subsidies will be eliminated by the Market Rules. This could tempt the transmission and dispatch authorities to divert power from distribution companies which purchase power to nonpaying distribution companies.

However, if the major distribution companies are owned by investors, while there will be resentment at the requirement that customers pay their bills, there will also be widespread 24 hour supply of electricity. Nonpaying regions will be fewer, with less political influence, and with limited ability to divert power from paying customers. The availability of a secure source of funding, from domestic distribution companies and export sales will encourage the privatization of generation assets. So bundling distribution companies which in isolation would be unattractive assets with generation facilities can hasten the transition to a financially functioning electricity system.