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Hydropower Investment Promotion Project (HIPP)

HIPP SPECIAL STUDIES, ANALYSIS AND DATA DEVELOPMENT

GEORGIAN TRANSMISSION SYSTEM COST ANALYSIS

October, 2010

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USAID HYDROPOWER INVESTMENT PROMOTION PROJECT (HIPP)

CONTRACT NUMBER: EEM-I-00-07-00005-0

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IN COLLABORATION WITH BLACK & VEATCH AND PIERCE ATWOOD ATTORNEYS LLC.

USAID/CAUCASUS OFFICE OF ENERGY AND ENVIRONMENT

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HIPP SPECIAL STUDIES, ANALYSIS AND DATA DEVELOPMENT[1]

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Export from the HPP's to be constructed under the HIPP project requires use of the transmission lines currently operated by and being built by, the Georgian transmission system operator GSE. While published GSE transmission tariffs exist, these are expected to change as new facilities are constructed and included to rate base. The tariff methodology currently in effect requires a "cost plus" return on equity method of finding revenue requirements. The present rate design is essentially a "postage-stamp" tariff that charges a single fee, on a peak monthly demand basis, stated as a per kwh tariff. This tariff also differs by voltage level.

To assess implications of changes in this tariff as plant is added would require detail, including on allocation of existing plant among voltage levels. Such data is not at this time available to the project, though total contracted costs for certain new facilities is known. The detailed method of rate design for the GSE system, to be applied by the Georgian Regulator including new facilities, is not presently known, indeed is widely debated based principally on arguments related to impacts on Georgian consumers. The Ministry of Energy has expressed that the new plant should not be charged to Georgian consumers, based apparently on belief that doing so necessarily significantly raises costs to such consumers. Our preliminary analysis of GSE costs, with and without the new plant and expected export and transit volumes, shows that this assumption may not be correct; in reasonable circumstances and rate designs, costs of use of the GSE transmission system might actually be lower than at present.

Thus, for present purposes our analysis concentrates on impact per kwh of various concepts, not a detailed rate design. Given aggregated financial data from the GSE 2009 Annual Report and the 2009 Audit Report, and data gleaned from various prior studies, we first created a regulatory style cost of service revenue requirement estimate for the existing GSE. For present discussion purposes, we include the subsidiaries of GSE and their existing or potential assets, as costs of GSE; that is, we study options for pricing of facilities, not for internal corporate organization of ownership of those facilities. Using various assumptions on pricing of the full current

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[1] HIPP Project Studies in support of Subtask 1-B: Carry out assessments, prefeasibility and other studies, and other research, to present as complete a picture as possible of the current legal/policy/regulatory structure, hydropower potential, investment opportunities, and the investment climate for small and medium hydropower development.

and incremental new partial systems, we then compute an average total cost per kwh. This resembles the form of a "postage stamp" tariff, but the analysis is not intended as a recommendation as to rate design. It is an impact analysis to assess various options.

The existing Georgian transmission and dispatch tariffs are given by GNEWRC Resolution 33, summarized in Table 1. The entries for GSE Transmission and Dispatch must be added for a total payment to GSE, by voltage level. The SaqRusEnergo tariff is reported here for completeness. Values are in Tetri/KWH, that is, "GEL-cents"/KWH.

Table 1: *High Voltage Transmission Rates, Per GNEWRC Resolution 33*

Transmission, Dispatching Tariffs

In Tetris	Voltage				
Per GNEWSRC Resolution 33	0,4 KV	6-10 KV	35-110 KV	220 KV	500KV
GSE Transmission		1.109	0.500	0.500	
GSE Dispatch	0.150	0.150	0.150	0.150	0.150
SAQRUS ENERGO	0.180	0.180	0.180	0.180	0.180

In US $ @	Voltage				
1.85	0,4 KV	6-10 KV	35-110 KV	220 KV	500KV
GSE Transmission	0.000	0.599	0.270	0.270	
GSE Dispatch	0.081	0.081	0.081	0.081	0.081
SAQRUS ENERGO	0.097	0.097	0.097	0.097	0.097

Annex A summarizes details of our analysis of average total costs of GSE. We compare the computed averages to the above published tariffs, as well as compare options for different organization of how plant and related volumes might be allocated for pricing purposes. Some regulatory issues implied by those costs, and principal conclusions on impacts of different choices are summarized next.

- In 2009, GSE revalued its assets, to reflect an assessment of replacement costs of assets. This resulted in a significant increase in gross and net book values, and in the total assets and liabilities (including equity) shown on the balance sheet of GSE after the revaluation. The intended purpose of the revaluation is not clear. However for regulatory purposes, most often regulators do not use such revaluations for determining tariffs. The currently required GNEWRC tariff philosophy is stated to be a "cost plus" method; when actually employed, such method therefore would include depreciation on rate base, and return on rate base, as critical components. So, if GSE intends the revaluation for such use, then at such time as GSE tariffs are recomputed, there will be probably a significant policy issue as to whether the Regulator will allow revalued costs for such computations. Our analysis shows an estimated rate base using both the pre- and the post-revaluation rate base amounts. These are represented in Annex A as “2008” for pre-revaluation, and “2009” for post-revaluation.

- Because regulatory treatment may and likely will differ from how GSE states its 2009 Annual Report, we used certain judgments to estimate a revenue requirement. To compute a total estimated current revenue requirement, we use the pre-revaluation rate base, from 2008, since that is closer to the likely cost structure to be used, reflecting standard regulatory treatment. However, for operating costs, the most current totals are probably the more representative, so to compute current revenue requirements we use 2009 operating costs.

- We do not have data separating plant by voltage levels, and lack other data critical to an analysis and recommendation of a “proper” rate design for GSE. Nor has HIPP been tasked to make such a recommendation. Thus our analysis of GSE unit cost impacts is simply of average total costs. The volumes used for such averages are a currently estimated Georgian volume, plus certain estimates of possible additional volumes from the HIPP tasked 400 MW of HPP, and from other possible Georgian export or transit volumes. The analysis of such volumes is done based on estimated capacity factors, by season, as further explained in Annex A. We have not conducted a “forecast” of Azeri nor any other transit volumes, nor of likely export volumes from Georgian HIPP plants; we simply estimate the volumes possible on the net capacity that would be available after transmission is dedicated first to the use of the new HPP units, as would be required by Georgian law, assuming various load factors by season. Detailed estimates of volumes can be better undertaken when the Black and Veatch site studies have been completed; and more so, when actual contracts with investors have been let.

- The analysis shows that the total dispatch plus transmission costs per kwh of GSE is currently about 0.0066 GEL/kwh. This compares to current posted tariffs (for the GSE 220 kv system) of 0.0050 GEL/kwh (0.50 Tetri) for transmission plus 0.0015 GEL/kwh (o.15 Tetri) for dispatch or a total of 0.0065 GEL/KWH. That is, on a pre-revaluation basis, the current GSE tariffs are approximately what a cost based average total cost would appear to require.

- If the revalued GSE asset rate base is used to estimate the cost of capital portion of a revenue requirement, then the average total costs are 0.0097 GEL/kwh, or about 50% higher than at present. The principal difference between these two values is that if the revalued rate base were used, and thus the tariff set at 0.0097 GEL/kwh, GSE would internally generate additional capital for new investment and maintenance. This statement assumes that for income tax purposes, the revalued amount would be the basis used for attributing depreciation expense; if the tax laws do not permit this, then if the tariff is set higher based on the revaluation, the “profit” for tax purposes will be higher, and thus taxes much higher, than if the pre-revalued rate base is used. These additional income taxes would result in the expanded capacity for internal cash generation being reduced.

- The choice to use the revalued rate base would thus add about 0.30 GEL/kwh to the transmission tariff, on an average over current Georgian domestic volumes. This effect is completely separate from the effect of new plant that may be added to the GSE rate base, such as via the Black Sea transmission project.

- The Black Sea transmission project is assumed in its feasibility analyses to also allow addition of volumes to the operation of the Georgian system, for transit (from Azerbaijan to Turkey), for export of the HPP plants to Turkey, and for other Georgian export. The volume assumed for such purposes is critical. If the project costs are averaged over only those volumes (thus also ignoring reliability impacts within Georgia) the result is very different than if the costs are averaged over total of all Georgian volumes, plus the incremental volumes.

- Looking just at the Black Sea project costs, on the assumed incremental volumes (and assuming a 650 MW import limit via the HVDC converter to Turkey, as is expected from the contracts and other limits currently in place), then the average total costs estimated in Annex A for components of that project are:

  0.0127 GEL/kwh for the HVDC station output,

  0.0067 GEL/kwh for the new 500 KV lines and related substations within Georgia, and

  0.0004 GEL/kwh for the 400 KV line from the HVDC station to the Georgian border,

  for a total of 0.0197 GEL/KWH. This is comparable, approximately, to the ranges of costs that were discussed in various Black Sea feasibility studies. Because this total is much higher than the current GSE combined average cost of 0.0066 GEL/kwh, it may be the basis for belief that placing this plant into normal GSE rate base and tariffs, will "raise costs" to Georgian consumers.

- However, if one computes the sum of existing GSE plant plus the new transmission lines (apart from HVDC costs), and divides by the sum of Georgian domestic volumes plus incremental transit plus export volumes, the result is 0.0043 GEL/kwh, which is in contrast 50% *lower* than the existing average total cost of 0.0066 GEL/kwh, paid by Georgian consumers. The resulting total transit, or export, transmission costs are then the sum of the HVDC cost of 00127 GEL/kwh, plus the 400 KV line cost of 0.0003 GEL/kwh plus 0.0043 = 0.0177 GEL/kwh for those (transit or export) volumes exiting Georgia via the HVDC station. This sum is also lower than if all new transmission lines are averaged on just the incremental transit and export volumes. This analysis also implicitly recognizes the reliability effects on the Georgian system of use of the new substations and high voltage lines within Georgia.

- The above average total costs approximate an expected tariff if charged on a “postage stamp” basis. We do not here reach a recommendation on best rate design. However, the view that the new HV transmission lines (apart from the HVDC substation) should be included as part of the overall Georgian transmission system costs for GSE rate design purposes, is supported by separate analysis of the integrated nature of operations of the GSE high voltage system, including the new Black Sea transmission lines, to support all domestic loads; and by the clauses in the market rules that allow the Dispatch Licensee to pre-empt any facilities for domestic uses. It is apparent from the above analysis that if the expected transit and export volumes materialize, pricing the intra-Georgia portions accordingly would lower, not increase, the cost of use of GSE facilities for Georgian consumers.

Support for the above conclusions, and other details and issues, are found in Annex A. Annex A also computes effects on average total costs if the export capacity from Georgia were expanded by the combination of increasing the HVDC station capacity to 1000 MW, and corresponding increases on line capacity out from that station and onward within Turkey.

ANNEX A: ANALYSIS OF GSE TRANSMISSION SYSTEM COSTS

OVERVIEW:

This Annex analyzes certain issues of the total costs of the GSE system, with and without the new Black Sea Transmission Project costs. Much of the discussion of the Black Sea project has been of the impact of that project on Georgian consumers. Proper regulatory practice should advise that plant be paid for by those who use it, applying an accepted tariff method that employs international standards; it is not simply an analysis of whom can be made to pay for it, or what user should on some political basis, not pay for it. Under Georgian law the entity which would set such tariff is the GNEWRC. The method believed used by the GNEWRC is a “cost plus” computation, of finding a total revenue requirement including an allowed normal profit and depreciation on the rate base employed. Tariffs would then be designed to recover the sum of such costs. A view of costs for this project attributed to the Ministry of Energy, is that project costs should be charged fully to “export”, presumably meaning also transit, to avoid a negative impact on Georgian consumers. The interest of the Ministry in protecting consumers is natural, even if pricing as such is not their responsibility. The foundation for a belief that charging Black Sea transmission system costs to all users, including domestic users, will necessarily raise costs to domestic users, is not clear. We represent results for comparative purposes as an average total cost per kwh, on an annual basis. This is done for convenience; the result resembles the existing “postage stamp” rate design in its form, but we do not here advocate any specific rate form for use of that line and associated equipment.

The results of this brief analysis can be summarized easily. The average total cost of GSE at present, without including the Black Sea costs, using 2009 operating costs and depreciation and normal return on the net book value of existing plant, is about 0.0066 GEL/kwh. This is approximately equal to the sum of the existing high voltage tariff of 0.0050 GEL/kwh plus the dispatch tariff of 0.0015 GEL/KWH. If all of the costs of the new facilities (the substation works, the high voltage lines, and the HVDC converter station) are combined and divided by the hypothecated export plus transit volumes, then depending on volumes assumed, that average cost is from over 0.01 GEL/kwh to over 0.02 GEL/kwh. While this number is certainly higher than the 0.0066 GEL/kwh average total cost of GSE are present, it is not meaningful to compare those numbers; they are implicitly charged to different customers. In contrast, if the total high voltage lines and substations, other than the HVDC line, are included as costs of GSE< and divided by the total of Georgian volumes plus expected export plus transit volumes, the resulting average cost *drops*, to a range of about 0.0044 to 0.0033 GEL/kwh. That is, if the plant were priced that way the cost to Georgian consumers is lower, than if the costs are separated. The HVDC station costs are still of course a large increment, in addition to the above average costs. We also present several examples of comparative impacts of different treatments of those costs in the following.

ASSUMPTIONS OF THE STUDY:

The analysis rests on a variety of computations assumptions, listed in the table below. One of the key issues involves deciding the basic financial data source. In 2009 GSE performed a revaluation of its assets, to reflect current values, rather than net original book values. The effect of such revaluation was to increase the claimed value of both total assets and total equity of the company. Both total assets (total value of plant used and used for the operation of the regulated services) and total equity, affect the computation of an annual revenue requirement, in somewhat different ways. Using these balance sheet accounts after valuation, for computing a "cost plus" tariff, would increase the revenue requirement computed, and thus, increase average costs when divided by similar volumes. However, in general, regulators do not use revalued assets for computing tariffs. The differences in resulting tariffs can be quite large. We treat that issue here by computing average total costs for revenue requirements using the original net book costs, and also, using the revalued assets. Both averages appear in our tables. The pre-revaluation assets are last reported as of end of 2008, and the revalued assets as of end of 2009; thus the columns are labeled with those years. However, for operating costs, the most recent year data is probably the most representative. Therefore, for GSE operating costs we use only the 2009 income statement. In most of our narratives, such as in the Overview above, we discuss GSE revenue requirements as the sum of capital costs based on the pre-revaluation assets (from 2008), and the more current 2009 operating costs. It would have been preferable to non-revalued net book values as of 2009, but such data is not available to us.

The Black Sea facilities are normally presented as three sets of numbers: those for the combined costs of substation construction or rehabilitation; those for the costs of the new 500 and 400 kv high voltage lines; and those for the HVDC converter. Four our purposes, the analysis of average total costs, as might be grouped for purposes of pricing would be organized somewhat differently. The issues of who would pay for the HVDC converter are specific to that unit, so the HVDC costs are treated separately. However, the likely uses of the substations and the new high voltage lines, is somewhat different than the organization of construction contracts. The portion of high voltage line between the HVDC converter would only be used by those volumes existing that converter; we thus allocate a portion of the high voltage construction (and assumed operating) costs to that section of line. The remaining high voltage lines (which is most of that equipment), and the substations, are then all grouped as a single total; this may or may not reflect physical use of all parts of that equipment and lines, but it does reflect discussions of how costs should be allocated. Thus we compute average costs by three components, as follows: for the HVDC converter; for the small segment of line from that converter to the Turkish border; and for all the remaining equipment.

Certain parameters numerical must be assumed for the study. Principal of these are the exit volumes from the HVDC converter (believed to be initially limited on the Turkish side to 650 MW, but expected to be expanded to 1000 MW capacity when a second 400 kv line is built on the Turkish side, and coincident with that, if also the HVDC converter adds a third unit raising its native capacity from 700 MW (2 x 350) to 1050 MW (3 x 350). If those also occur, then the costs for the line between HVDC station and the border, and for the HVDC unit itself, will also increase. These values are thus controlled by certain assumptions, and "switches", summarized in the table. Details of most other assumptions are listed in the following tables, and are we hope self-explanatory.

However, we explain further the structure of Table A.8, illustrating estimation of seasonal volumes through the HVDC station out toward Turkey. The maximum throughput of that station is constrained by two factors. The first is the physical capacity of the HVDC station itself. As presently designed we understand that station consists to two 350 MW converters, for a total of 700 MW. There is an stated intent, not yet contracted, to ex[and that station with a third 350 MW converter, to thus a total of 1050 MW. However, the flow out from that station then must enter certain transmission lines, and also, be within the physical constraints allowed by the Turkish system for receipt to its lines. We understand that the initially planned 400 kv high voltage transmission line out from the HVDC station, to the interconnection point in Turkey, is constrained by the Turkish side at 650 MW. Thus, the constraint on total flow through the HVDC station as it will be initially constructed and contracted, is 650 MW, not 700 MW. We are informed that an agreement has been made between Turkey and Georgia, to construct a second 400 kv line connecting the HVDC station to the Turkish grid, and that this second lines would have a capacity of 1000 MW. Superficially, that implies a maximum flow capacity of 1650 MW, once completed. However, that capacity could only be accessed if the HVDC station capacity allows 1650 MW; but as currently designed, with the expected third converter, maximum would be only 1000 MW. Thus the maximum flow with the second 400 kv line on the Turkish side of the HVDC station is also analyzed as 1000 MW, not 1650 MW. (We also note, that from a reliability perspective, if a constrained path contains 650 MW and 1000 MW parallel lines, that the N-1 contingency outage constrained should be rated as 650 MW. However we are not here evaluating implications of reliability on pricing.)

We next note that seasonal flows will differ in both Georgia and Turkey, and that within Georgia, the legal requirement for preferred access for renewables therefore affects net available capacity from the HVDC station, after priority to renewables is considered. Specifically for the HIPP project, we must consider the effect of presence of 400 MW of HPP, by season, and thus also, of net available capacity by season.

Thus, Table A.8 shows how these priorities were used to estimate maximum seasonal and annual volumes, in the case when the maximum HVDC capacity is 650 MW. The seasonal assumptions and computations are as follows: in the summer season, the maximum rated coincident peak capacity of the HIPP hydros will be reached. Thus, the net available capacity at peak will be 650 – 400 = 250 MW. The HIPP project hydros perform, in that season at 90% capacity factor, and the remaining net capacity is used by all other uses (transit and other export) at 80% capacity factor. In winter, the coincident peak use of the HIPP plants is estimated at only 100 MW, for a net available for other uses of 550 MW. The HIPP plants are assumed to flow at 50% capacity factors in winter and the remaining (transit plus other exports) at 80% capacity factors.

The same assumptions and computation methods were used for the case of 1000 MW. The results for the 650 MW case are then given in Tables A.9 and A.10, and for the 1000 MW case in Table A.11 and A.12.

Note also, therefore, we are not here "forecasting" either transit volumes (such as from Azerbaijan) nor other Georgian export volumes. We are simply analyzing the potential consequences upon successful tender of the HIPP project 400 MW of new capacity.

Table A.1: *Assumptions used in GSE Transmission Cost Analysis*

Structural Assumptions of GSE Average Transmission Cost Analysis:
Computes average costs/kwh; a "tariff" might be charged differently than simple volumes flowed.
Average total cost combines Transmission and Dispatch.
Transmission plant not classified by voltage level.
"Black Sea" refers to Black Sea Project.
Black Sea 400 and 500 KV Lines and Substation Costs Combined.
HVDC Costs Applied on on Volumes that Use the Converter.
HVDC Transit from Flow Estimates, assume Priority to Georgian Producers.
"Stand Alone" Volumes an ad hoc estimate of annual Georgian volumes, apart from Export or Transit.
All depreciation recovered in revenue is reinvested in equivalent rate base (rate base constant).
"Georgia Stand Alone" Divides selected total costs by Georgian domestic total volumes.
"Georgia Total Volumes" Sums the HVDC volumes plus Georgia domestic volumes.
"T+E Volumes" means the sum of transit volumes and Georgian export volumes exiting the HVDC.
Sakrusenergo Costs, Tariffs and Volumes are ignored.
GSE O&M and G&A Expenses use the GSE 2009 Audit totals.
GSE Rate Base Computed for both pre-revaluation (2008 totals) and post-revaluation (2009 totals).
Black Sea Project Capital Costs Based on GSE Reports of total contract values as of September 2010.
Black Sea Project Operating Costs estimated as equivalent to a simple percent of total capital cost.
Note: Fitchner Assumed Annual O&M = 1.5% of "Investment".
Cost of Loans to GSE at 2009 Weighted Average Cost of all IFI Loans shown in the 2009 Audit.
Cost of Equity to GSE Assumed as ad hoc 10%; all shares are Government Owned.
WACC uses Averages based on Balance Sheet of 2009 Post-Audit.
Transmission Losses are not part of tariff comptuations by GNERC, and are not considered here.
Assumed parameters in HVDC and 400 kv line expansions have "yes = 1" and "no = 0".
Selection causes "GSE Average Costs per kwh" to be computed accordingly.

Table A.2: *Numerical Assumptions used in GSE Transmission Cost Analysis*

Assumed Values:			
Rates:		Depreciation Terms:	Years:
Dollar - GEL Exchange Rate	1.85	Buildings and Constructions	20
Euro - GEL Exchange Rate	2.49	Power Transmission Lines	20
Georgian Income Tax Rate	10%	Vehicles and equipment	5
GSE Cost of Equity	10%	Other (CWIP)	6.5
Black Sea O&M As Percent of Capital Cost	1.50%	HVDC	20
		Black Sea HV Lines	20
HVDC and 400 kv Line Expansion		Black Sea Substations	20
Maximum HVDC Transit Capacity	650		
Build Second 400 kv Line to Turkey	0		
Expand HVDC to 3rd Converter	0		
Expansion HVDC Cost as % of Original Cost	25%		

The above assumptions reflect the 650 MW case. In the 1000 MW flow capacity case, the Maximum HVDC Capacity would be set at 1000 MW, the two switches for Build Second 400 kv Transmission Line to Turkey and Expand HVDC to 3rd Converter would be set at 1. The additional cost of that expansion would then be estimated as equal 25% of the original construction cost of the HVDC station. See Table A.8 for application of other assumptions in computing potential through-volumes of the HVDC station.

Table A.3: *GSE Estimated Revenue Requirements Based on Data Before and After Revaluation*

GSE Annual Operating and Capital Costs		
Lari 1000	**Historical**	**Revalued**
Revenues:	**2008**	**2009**
Transmission	35,428	32,318
Dispatching	11,223	10,554
	46,651	42,872
Interest on Deposits	1,547	3,158
Total Regulatory Income	48,198	46,030
Other Operating Income	15,247	41,046
Total Revenues	63,445	87,076
Expenses:	**2008**	**2009**
Network Operating Costs	562	3,516
Administrative Expenses	3,034	3,557
Payroll and Employee Benefits	12,615	13,173
Other Operating Expenses	1,703	14,016
Total	17,914	34,262
Cost of Capital	**2008**	**2009**
Allowed Return	9,593	23,676
Income Tax	1,066	2,631
Depreciation	21,558	36,295
Total	32,218	62,602
Total Revenue Requirement	50,132	96,864
Annual Volumes (2009)		**GWH**
Distribution Companies		5,931
Direct Customers		1,700
Own Consumption		12
Export		749
Total		8,391
Implied Average Fee, GEL/kwh	0.00597	0.01154
Transmission Plus Dispatch		
(Omits cost of losses)		
Implied Average Fee $/kwh	0.00323	0.00624
Transmission Plus Dispatch		
(Omits cost of losses)		
SOURCE: GSE 2009 AUDITOR'S REPORT		

Table A.4: *GSE Assets Before and After Revaluation*

GSE Assets and Depreciation, Before and After Revaluation

	Lari 1000			Lari 1000				
	GSE Assets Before Revalue			**GSE Assets After Revalue**				
	Total Cost on	Depreciation up to	Net Book Value at	Total Cost on	Change in 2009	Net Book Value at	Change in Book Value	Term
Class	12/31/2008	12/31/2008	12/31/2008	12/31/2009	12/31/2009	12/31/2009	12/31/2009	Years
Buildings and Constructions	16,083	8,623	7,460	58,147	13,637	44,510	37,050	20
Power Transmission Lines	335,155	293,386	41,769	136,315	13,942	122,373	80,604	20
Vehicles and equipment	151,479	100,613	50,866	110,500	35,103	75,397	24,531	5
Other (CWIP)	79,567	21,562	58,005	115,558	31,892	83,666	25,661	6.5
Total	582,284	424,184	158,100	420,520	94,574	325,946	167,846	
Estimated Annual Depreciation								
Buildings and Constructions			373			2,226	1,853	20
Power Transmission Lines			2,088			6,119	4,030	20
Vehicles and equipment			10,173			15,079	4,906	5
Other (CWIP)			8,924			12,872	3,948	6.5
Total			21,558			36,295	14,737	

Table A.5: *GSE Capital Structure Before and After Revaluation*

GSE Capital Structure, Rate Base and Cost of Capital				
			WACC	
Capital Structure	**2008**		Cost	Total
Liabilities	172,258	90.61%	5.11%	4.63%
Equity	17,858	9.39%	10.00%	0.94%
Total	190,116	100.00%		5.57%
	2009			
Liabilities	219,398	56.20%	4.52%	2.54%
Equity	171,003	43.80%	10.00%	4.38%
	390,401	100.00%		6.92%
Rate Base	**2008**		**2009**	
Net Book Value	158,100		325,946	
Cash Working Capital (YE Cash)	14,280		16,136	
Rate Base Total	172,380		342,082	
Allowed WACC	5.6%		6.9%	
Return on Rate Base	9,593		23,676	
Income Tax Rate	10%		10%	
Income Tax, @ rate =	1,066		2,631	
Total Cost of Capital	**2008**		**2009**	
Allowed Return	9,593		23,676	
Income Tax	1,066		2,631	
Depreciation	21,558		36,295	
	32,218		62,602	

Table A.6: *GSE Liabilities Structure Before and After Revaluation*

GSE Debt Structure and Other Liabilities						
	Lari 1000					
Loans and Borrowings, 2008	**Current**	**Non-Current**	**Total**	**Rate**	**Cost**	
Mof Georgia (IDA)	4,401	38,751	43,152	7.79%	3,362	
Mof Georgia (KfW)	2,354	47,378	49,732	1.94%	965	
Total	6,755	86,129	92,884	4.66%	4,326	
Loans and Borrowings, 2009	**Current**	**Non-Current**	**Total**	**Rate**	**Cost**	
Mof Georgia (IDA)	4,926	43,182	48,108	7.79%	3,748	
Mof Georgia (KfW)	2,402	66,517	68,919	1.94%	1,337	
Total	7,328	109,699	117,027	4.34%	5,085	
Other Liabilities	**2008**	**Rate**	**Cost**	**2009**	**Rate**	**Cost**
Restructured Liabilities	50,346	9.50%	4,783	54,251	9.50%	5,154
Grants Related to Assets	5,814	-	-	5,286	-	-
Deferred Income Tax	-	-	-	9,139	-	-
Deferred VAT	8,041	-	-	8,023	-	-
Sub Total	64,201		4,783	76,699		5,154
Long Term Loans	86,129		4,012	109,699		4,766
Total Other Liabilities	172,258	5.11%	8,795	219,398	4.52%	9,920

Table A.7: *Analysis of Black Sea Project Component Regulatory Cost of Capital*

BLACK SEA PROJECT PLANT ADDITIONS						
	Capital Cost		Annual Expenses			
Exchange rate =	(million)	GEL 1000	Str. Line	O&M @	WACC @	
2.486	Euro	Contract	Deprec.	1.50%	6.92%	Years
HVDC	133.80	332,627	16,631	4,989	23,022	20
HV Lines	55.60	138,222	6,911	2,073	9,567	20
Substations	35.70	88,750	4,438	1,331	6,143	20
Total	225.10	559,599	27,980	8,394	38,731	

COST OF PLANT FROM HVDC TO TURKISH BORDER						
Line Length		KM	Values in GEL 1000			
New 500 and 400 kv		300				**Revenue**
HVDC to Turkey		25				**Require.**
Percent of Cost		8.33%	**Str. Line**	**O&M @**	**WACC @**	**Total**
Cost of Line to Turkey		11,518	576	173	797	1,546
Include Second?	Yes = 1	0				
Cost of 2nd 400 KV		11,518	576	173	797	1,546
Total Cost, 400 kv Lines		11,518	576	173	797	1,546
Expand HVDC?	Yes = 1	0	Percent of Cost Added =			25%
		Capacity	**Deprec.**	**O&M**	**WACC**	**Total**
Additional HVDC Costs		83,157	4,158	1,247	5,755	11,161

Table A.8: *Analysis of HVDC Station Output Volumes, By Season, 650 MW Maximum Flow Scenario*

HVDC Station Seasonal and Annual Volumes, Detail		
SEASONAL USE ANALYSIS:		
Summer Months		
Months in Period	6	
SHPP Use of Peak, Summer	400	MW
SHPP Load Factor, Summer	90%	
SHPP Volumes, Summer	1,577	GWH
Net Peak Capacity, Summer	250	MW
Net Firm Volume Available, Summer	1,095	GWH
Assumed Load Factor for Net Use, Summer	80%	
Net Transit and Other Export, Summer	876	GWH
Winter Months		
Months in Period	6	
SHPP Use of Peak, Winter	100	MW
SHPP Load Factor, Winter	50%	
SHPP Volumes, Winter	219	GWH
Net Peak Capacity, Winter	550	MW
Net Firm Volume Available, Winter	2,409	GWH
Assumed Load Factor for Net Use, Winter	80%	
Net Transit and Other Export, Winter	1,927	GWH
Annual Line Use Estimates, Summary		
Summer		
Transit	876	GWH
Export	1,577	GWH
Total summer volumes	2,453	GWH
Winter		
Transit	1,927	GWH
Export	219	GWH
Total winter volumes	2,146	GWH
Total Annual Volumes	4,599	GWH

Table A.9: *GSE Revenue Requirements, 650 MW Maximum HVDC Flow Scenario*

Transmission System Revenue Requiements				
GSE Revenue Requirement:	**2008**	**2009**		
O&M and G&A Expenses (at 2009 levels)		34,262		
Cost of Capital, by Basis Year	32,218	62,602		
Total Revenue Requirement	66,480	96,864		
Black Sea Project Costs	**Lines**			
Expenses:	**+ Subst.**	**HVDC**	**Total**	
Estimated Total Annual O&M	3,405	4,989	8,394	
Cost of Capital				Rate:
Allowed Return	15,709	23,022	38,731	6.92%
Income Tax	1,745	2,558	4,303	10.00%
Depreciation	11,349	16,631	27,980	
Total	28,803	42,211	71,014	
Black Sea Revenue Requirement, Total	32,208	47,200	79,408	
Less: Initial 400 kv to Turkey	1,546			
Black Sea Revenue Requirement, Net	30,662	47,200	77,862	
400 kv From HVDC to Turkey	1,546		0	Yes = 1
Additional HVDC Station Costs		11,161	0	Yes = 1
Total HVDC Station Costs		58,361		

Table A.10: *GSE Average Costs per kwh, 650 MW Maximum HVDC Flow Scenario*

Transmission System Average Unit Costs				
Annual Volumes	**Georgia Alone**	**Georgia + HVDC Out**	**HVDC Out T+E Vols**	
Volumes Through HVDC, Transit Plus Export		4,599	4,599	GWH
Georgia Stand Alone Volumes, 2010 Est	10,000			GWH
Total	10,000	14,599	4,599	GWH
Estimated Average Costs/kwh (GEL) Transmission + Dispatch + Substations	**Georgia Alone**	**Georgia + HVDC Out**	**HVDC Out T+E Vols**	
GSE Existing (2009 Valuation) Costs	0.0097			GEL/kwh
GSE Existing (2008 Valuation) Costs	0.0066			
GSE Existing (2009) Plus Black Sea Costs	0.0128	0.0087		GEL/kwh
GSE Existing (2008) Plus Black Sea Costs	0.0097	0.0043		
Black Sea Costs Separated				
HVDC			0.0127	GEL/kwh
400 kv From HVDC to Turkey			0.0003	GEL/kwh
Black Sea Lines on HVDC Volumes			0.0067	GEL/kwh
HVDC + Black Sea on HVDC Volumes			0.0197	GEL/kwh
HVDC + Black Sea on All Volumes (2009 RB)		0.0154		GEL/kwh
HVDC + Black Sea on All Volumes (2008 RB)		0.0110		GEL/kwh
Assumption Summary:				
HVDC Expanded?	0	Yes = 1		
400 KV Expanded?	0	Yes = 1		
MW Out from HVDC	650	MW		
Estimated Average Costs/kwh ($) Transmission + Dispatch + Substations	**Georgia Alone**	**Georgia + HVDC Out**	**HVDC Out T+E Vols**	1.85 Exc. Rate
GSE Existing (2009 Revaluation) Costs	0.0052			$/kwh
GSE Existing (2008 Valuation) Costs	0.0036			$/kwh
GSE Existing (2009) Plus Black Sea Costs	0.0069	0.0047		$/kwh
GSE Existing (2008) Plus Black Sea Costs	0.0053	0.0023		$/kwh
Black Sea Costs Added				
HVDC			0.0069	$/kwh
400 kv From HVDC to Turkey			0.0002	$/kwh
Black Sea Lines on HVDC Volumes			0.0036	$/kwh
HVDC + Black Sea on HVDC Volumes			0.0106	$/kwh
HVDC + Black Sea on All Volumes (2009 RB)		0.0083		$/kwh
HVDC + Black Sea on All Volumes (2008 RB)		0.0059		$/kwh

Table A.11: *GSE Revenue Requirements, 1000 MW Maximum HVDC Flow Scenario*

Transmission System Revenue Requiements				
GSE Revenue Requirement:	**2008**	**2009**		
O&M and G&A Expenses (at 2009 levels)		34,262		
Cost of Capital, by Basis Year	32,218	62,602		
Total Revenue Requirement	66,480	96,864		
Black Sea Project Costs	**Lines**			
Expenses:	**+ Subst.**	**HVDC**	**Total**	
Estimated Total Annual O&M	3,405	4,989	8,394	
Cost of Capital				Rate:
Allowed Return	15,709	23,022	38,731	6.92%
Income Tax	1,745	2,558	4,303	10.00%
Depreciation	11,349	16,631	27,980	
Total	28,803	42,211	71,014	
Black Sea Revenue Requirement, Total	32,208	47,200	79,408	
Less: Initial 400 kv to Turkey	1,546			
Black Sea Revenue Requirement, Net	30,662	47,200	77,862	
400 kv From HVDC to Turkey	3,092		1	Yes = 1
Additional HVDC Station Costs		11,161	1	Yes = 1
Total HVDC Station Costs		58,361		

Table A.12: *GSE Average Costs per kwh, 1000 MW Maximum HVDC Flow Scenario*

Transmission System Average Unit Costs				
Annual Volumes	**Georgia Alone**	**Georgia + HVDC Out**	**HVDC Out T+E Vols**	
Volumes Through HVDC, Transit Plus Export		7,052	7,052	GWH
Georgia Stand Alone Volumes, 2010 Est	10,000			GWH
Total	10,000	17,052	7,052	GWH
Estimated Average Costs/kwh (GEL) Transmission + Dispatch + Substations	**Georgia Alone**	**Georgia + HVDC Out**	**HVDC Out T+E Vols**	
GSE Existing (2009 Valuation) Costs	0.0097			GEL/kwh
GSE Existing (2008 Valuation) Costs	0.0066			
GSE Existing (2009) Plus Black Sea Costs	0.0128	0.0075		GEL/kwh
GSE Existing (2008) Plus Black Sea Costs	0.0097	0.0037		
Black Sea Costs Separated				
HVDC			0.0083	GEL/kwh
400 kv From HVDC to Turkey			0.0004	GEL/kwh
Black Sea Lines on HVDC Volumes			0.0043	GEL/kwh
HVDC + Black Sea on HVDC Volumes			0.0131	GEL/kwh
HVDC + Black Sea on All Volumes (2009 RB)		0.0118		GEL/kwh
HVDC + Black Sea on All Volumes (2008 RB)		0.0080		GEL/kwh
Assumption Summary:				
HVDC Expanded?	1	Yes = 1		
400 KV Expanded?	1	Yes = 1		
MW Out from HVDC	1000	MW		
Estimated Average Costs/kwh ($) Transmission + Dispatch + Substations	**Georgia Alone**	**Georgia + HVDC Out**	**HVDC Out T+E Vols**	1.85 Exc. Rate
GSE Existing (2009 Revaluation) Costs	0.0052			$/kwh
GSE Existing (2008 Valuation) Costs	0.0036			$/kwh
GSE Existing (2009) Plus Black Sea Costs	0.0069	0.0040		$/kwh
GSE Existing (2008) Plus Black Sea Costs	0.0053	0.0020		$/kwh
Black Sea Costs Added				
HVDC			0.0045	$/kwh
400 kv From HVDC to Turkey			0.0002	$/kwh
Black Sea Lines on HVDC Volumes			0.0024	$/kwh
HVDC + Black Sea on HVDC Volumes			0.0071	$/kwh
HVDC + Black Sea on All Volumes (2009 RB)		0.0064		$/kwh
HVDC + Black Sea on All Volumes (2008 RB)		0.0043		$/kwh

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