GEORGIA POWER COMPANY
Docket No. 31958
GIG-GTMA Information Request No 1

GIG-GTMA-1-8

Question:

Please provide all workpapers used to determine the $45 million base revenue reduction due to the proposed RTP accounting change.

Response:

Please see the Company's response to STF-TAI-2-23.

GEORGIA POWER COMPANY
Docket No. 31958
GIG-GTMA Information Request No 1

GIG-GTMA-1-10

Question:

Please provide the hourly replacement fuel costs that were used in determining the impact of changing the fuel cost accounting mechanism in the RTP program in electronic (EXCEL or compatible) format. If not otherwise provided, please provide the corresponding hourly RTP-DA and RTP-HA prices for the same hours in electronic (EXCEL or compatible) format.

Response:

Please see the Company's response to STF-TAI-2-23.

GEORGIA POWER COMPANY
Docket No. 31958
GIG-GTMA Information Request No 2

GIG-GTMA-2-12

Question:

If not provided in previous requests, please provide a schedule showing the fuel cost recoveries attributable to RTP-DA and RTP-HA:

a. Under the present fuel accounting methodology.

b. Under the proposed fuel accounting methodology.

Response:

Please see the Company's response to STF-TAI-2-23.

GEORGIA POWER COMPANY

Docket 31958

Georgia Power Company's
2010 Rate Case

DATA REQUEST TRANSMITTAL

DATA REQUEST NO. STF-HC-2 **TRANSMITTAL DATE** August 12, 2010

QUESTION #	RESPONSE STATUS	COMMENTS
6	COMPLETE	NONE

GEORGIA POWER COMPANY
Docket No. 31958-U
Staff Data Request Set No. STF-HC-2

STF-HC-2-6

Question:

On page 12, lines 3-12 of his testimony, Mr. Roberts states that, due to a revised RTP pricing methodology, the Company's proposed 2011 test year's base revenues were increased by $10.5 million and that, if the PSC were to reject this new pricing methodology, this would have the effect of "raising the revenue requirement allocated to embedded rates by $10.5 million."

In addition, on page 13, lines 9-13 of his testimony, Mr. Roberts states that, due to an RTP accounting methodology change, GPC's proposed overall revenue requirement for its proposed ARP test year, calendar year 2011, was reduced by $45 million.

With regard to the two statements referenced above, please provide the following clarifying information:

a. Explain whether the first statement means that if this new RTP pricing methodology is rejected, this will increase GPC's proposed ARP base rate increase of $451.462 million by $10.5 million. If not, provide the correct interpretation.

b. Explain whether the second statement means that if this RTP accounting methodology change is rejected, this will increase GPC's proposed ARP base rate increase of $451.462 million by $45 million. If not, provide the correct interpretation.

c. Explain whether the two above statements mean that if the Company's proposed new RTP pricing methodology and RTP accounting methodology change is rejected by the PSC, this will increase GPC's proposed ARP base rate increase of $451.462 million by a combined amount of $55.5 million. If not, provide the correct interpretation.

d. Explain whether the base revenue adjustment resulting from the proposed new RTP pricing methodology is reflected as a revenue contribution in the determination of GPC's 7/31/11 test year base revenue deficiency amount of $574.676 million shown on Exhibit APD/RBM-3, Schedule 1. If not, explain why not and show what the test year revenue deficiency amount of $576.676 million would be if this revenue contribution had been reflected. If so, provide the annualized revenue contribution (equivalent to the $10.5 million revenue contribution for the 2011 test year) that is reflected in the determination of the test year revenue deficiency amount of $576.676 million.

e. Explain whether the base revenue adjustment resulting from the proposed new RTP accounting methodology change is reflected as a revenue contribution

GEORGIA POWER COMPANY
Docket No. 31958-U
Staff Data Request Set No. STF-HC-2

in the determination of GPC's 7/31/11 test year base revenue deficiency amount of $574.676 million shown on Exhibit APD/RBM-3, Schedule 1. If not, explain why not and show what the test year revenue deficiency amount of $576.676 million would be if this revenue contribution had been reflected. If so, provide the annualized revenue contribution (equivalent to the $45 million revenue contribution for the 2011 test year) that is reflected in the determination of the test year revenue deficiency amount of $576.676 million.

Response:

a. Yes, that is the correct interpretation.
b. Yes, that is the correct interpretation.
c. Yes, that is the correct interpretation.
d. A base revenue adjustment of $11.1 million, resulting from the proposed new RTP pricing methodology, is included as a revenue contribution in the determination of GPC's 7/31/11 test year base revenue deficiency amount.
e. A base revenue adjustment of $19.071 million, resulting from the proposed RTP accounting methodology change, is included as a revenue contribution in the determination of GPC's 7/31/11 test year base revenue deficiency amount.

Contact Person: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-HC-2

STF-HC-2-30

Question:

Staff has prepared the attached Excel document Attachment STF-HC-2-30, summarizing Staff's understanding of the rate increases in 2011, 2012 and 2013 under the Company's proposed ARP. In this regard, please provide the following information:

a) Confirm that the total combined rate increases for 2011, 2012 and 2013 under GPC's proposed ARP amount to $1.152 billion. If the Company does not agree with this total number and/or any of the rate increase line items shown on Attachment STF-HC-2-30, please explain your disagreements and provide the answers that the Company believes are correct.
b) Please review Staff's understanding of the base rate revenue requirement mitigation (reduction) components and dollar amounts listed under footnote (1), items (a) through (g) and confirm that the numbers are accurate. If not accurate, please provide and explain the accurate information. In addition, if any additional revenue requirement mitigations were made by the Company that are not listed under footnote (1), please provide and explain these additional items.

Response:

a) The Company confirms the total combined rate increases requested for 2011, and as estimated for 2012 and 2013 under the proposed Adjustable Rate Plan (ARP) are reflected correctly in Attachment STF-HC-2-30.
b) Components of footnote 1 as identified by Staff are as follows:
    a. Delay of McDonough 4, 5 & 6 in-service dates, with a revenue requirement impact of ($78) million, --see the Company's response to STF-HC-2-13 for further explanation;
    b. Deferral to 2012 of T&D depreciation expense increase, with a net revenue requirement impact of ($87) million, --see the Company's response to STF-HC-2-16 for further explanation;
    c. Reduction of nuclear decommissioning costs, ($2.911) million, --see the Company's response to STF-HC-2-18 for further explanation;
    d. 3 year amortization of remaining COR balances, with a revenue requirement impact of $31 million, --see the Company's response to STF-HC-2-18 for further explanation;
    e. 12 year amortization of costs resulting from new health care regulations, with a net revenue requirement reduction in 2011 of ($52) million and an on-going revenue requirement of $4 million for the remaining 11 year amortization period --see the Company's response to STF-HC-2-18 for further explanation;

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-HC-2

f. Impact on base rate revenue requirements of RTP pricing method change is correct as indicated on Staff Attachment STF-HC-2-30 ($11 million);
g. Impact on base rate revenue requirements of RTP accounting method change is correct as indicated on Staff Attachment STF-HC-2-30 ($45 million);

The following items, representing additional actions by the Company to further mitigate revenue requirements, have been listed as (h) and (i) in Attachment STF-HC-2-30:

h. DSM costs with a net revenue requirement impact of ($11 million), --see the Company's response to STF-HC-2-18 for further explanation;
i. Three year amortization of deferred 2010 environmental costs with a net revenue requirement impact of ($14 million) --see the Company's response to STF-HC-2-18 for further explanation.

Contact Person: David Meiselman

Attachment STF-HC-2-30

GPC RATE CASE - DN 31958
RATE INCREASES UNDER
PROPOSED ALTERNATIVE RATE PLAN
USING CALENDAR 2011 AS STARTING TEST PERIOD
($MILLIONS)

Effective 1/1/11:			
- Base Rate Increase	$	451	(1)
- ECCR Rate Increase		115	Reflects $78 M cost deferral to 2012
- DSM Rate Increase		32	Reflects removal of $16 M additional sum and 3-yr amort. of 2010 deferral
- MFF Rate Increase		17	See APD/RBM-1, Sch. 1, Wp 1, page 3
- Total Rate Increase		615	
Effective 1/1/12:			
- Base Rate Increase (Through ACR)	$	133	See APD/RBM-1, Sch. 1, Wp 2, page 1
- ECCR Rate Increase		120	Includes 3-yr amortization of costs deferred in 2011, incl. carrying charges
- CCCR Rate Increase (2/12 and 6/12)		176	Due to in-service status of McDonough 4 and 5
- DSM Rate Increase		17	
- MFF Rate Increase		10	See APD/RBM-1, Sch. 1, Wp 2, page 6
- Total Rate Increase		456	
Effective 1/1/13:			
- Base Rate Decrease (Through ACR)	$	(13)	See APD/RBM-1, Sch. 1, Wp 3, page 1
- ECCR Rate Decrease		(12)	Includes 3-yr amortization of costs deferred in 2011, incl. carrying charges
- CCCR Rate Increase (2/13 and 12/13)		86	Due to in-service status of McDonough 6 and Mitchell biomass conversion
- DSM Rate Increase		18	
- MFF Rate Increase		2	See APD/RBM-1, Sch. 1, Wp 3, page 6
- Total Rate Increase		81	
Total Proj. Rate Increases 2011 - 2013:	$	1,152	

(1) Includes the following revenue requirement mitigation proposals:	Staff RR Impact	**GPC RR Impact**
a. Delay of McDonough 4, 5, 6 in-service dates to 2012 and 2013	$ (78)	**$ (78)**
b. Deferral to 2012 of T&D depreciation expense increase	(87)	**(83)**
c. Removal of certain nuclear decommissioning costs	(3)	**(3)**
d. 3-Year amortization of remaining unamortized Other COR reg. liability bal.	(31)	**(31)**
e. 12-Year amortization of costs resulting from new health care legislation	(52)	**(52)**
f. Impact on base rate revenue requirement of RTP pricing method change	(11)	**(11)**
g. Impact on base rate revenue requirement of RTP accounting change	(45)	**(45)**
h. 5 year amortization of deferred DSM costs		**(11)**
i. 3 year amortization of 2010 deferred environmental costs		**(14)**

SOURCES: APD/RBM-1 and 2

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-HC-2

STF-HC-2-31

Question:

Staff has prepared the attached Excel document Attachment STF-HC-2-31, summarizing Staff's understanding of the total $809 million rate increase based on using the legally mandated test year ended 7/31/11. In this regard, please provide the following information:

a) Confirm the accuracy of the rate increase component breakout with the related notes to the right of the dollar amounts. If the Company does not agree with this rate increase breakout and/or the related notes, please explain your disagreements and provide the answers that the Company believes are correct.
b) Please replace the question marks in items (a), (b), (c), (e), (f) and (g) under footnote (1). In addition, if any additional revenue requirement mitigations were made by the Company that are not listed under footnote (1), please provide and explain these additional items.

Response:

a) The Company confirms that the breakdown of the total revenue requirement associated with the test period ending 07/31/2011 as reflected in Staff Attachment STF-HC-2-31 is correct.

b) Please see Attachment STF-HC-2-31 for the revenue requirement mitigating impacts of items (a) through (g). Consistent with the response to STF-HC-2-30, the Company has included two additional items representing further actions to mitigate revenue requirement, --see items (h) and (i) on Attachment STF-HC-2-31.

Contact Person: David Meiselman

Attachment STF-HC-2-31

GPC RATE CASE - DN 31958
RATE INCREASES BASED ON TEST YEAR ENDED 7/31/2011
($MILLIONS)

Effective 1/1/11:			
- Base Rate Increase	$	575	(1)
- ECCR Rate Increase		181	Does not reflect $78 M cost deferral to 2012
- DSM Rate Increase		32	Reflects removal of $16 M additional sum and 3-yr amort. of 2010 DSM deferral **(?)**
- MFF Rate Increase		21	
- Total Rate Increase	$	809	

(1) Includes the following revenue requirement mitigation proposals:	Staff RR Impact
a. Delay of McDonough 4, 5, 6 in-service dates to 2012 and 2013	?
b. Deferral to 2012 of T&D depreciation expense increase	0
c. Removal of certain nuclear decommissioning costs	?
d. 3-Year amortization of remaining unamortized Other COR reg. liability balance	(31)
e. 12-Year amortization of costs resulting from new health care legislation	?
f. Impact on base rate revenue requirement of RTP pricing method change	?
g. Impact on base rate revenue requirement of RTP accounting change	?

(1) Includes the following revenue requirement mitigation proposals:	**GPC RR Impact**
a. Delay of McDonough 4, 5, 6 in-service dates to 2012 and 2013	**$ (33)**
b. Deferral to 2012 of T&D depreciation expense increase	**-**
c. Removal of certain nuclear decommissioning costs	**(3)**
d. 3-Year amortization of remaining unamortized Other COR reg. liability balance	**(31)**
e. 12-Year amortization of costs resulting from new health care legislation	**(52)**
f. Impact on base rate revenue requirement of RTP pricing method change	**(11)**
g. Impact on base rate revenue requirement of RTP accounting change	**(19)**
h. 5 year amortization of deferred DSM costs	**(11)**
i. 3 year amortization of 2010 deferred environmental costs	**(14)**

SOURCE: APD/RBM-3

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-19

Question:

Please provide all detailed workpapers and analyses supporting the proof of revenues under current and proposed rates (M.F.R., Item F-4) for each rate schedule. In this response, please also provide a detailed calculation showing the determination of each RTP base revenue component for CBL, Incremental, and Fuel Revenue. Please provide analyses in electronic (Excel) format.

Response:
See Attachment STF-TAI-2-19a through e on CD for the workpapers and analysis supporting the MFR-F4 proof of revenues for both current and proposed rates. Attachments STF-TAI-2-19a and STF-TAI-2-19b are the sources for Attachments STF-TAI-2-19c and STF-TAI-2-19d, respectively, and calculate kWh, customers and fuel revenue by rate. Additionally, the RTP base revenue components (CBL, Incremental and Fuel Revenue) are calculated in these files. Attachments STF-TAI-2-19c and STF-TAI-2-19d use the results from a and b to calculate base revenue by rate and associated tariffs. Finally, Attachment STF-TAI-2-19e contains the calculations for proposed rate revenue by rate and rate blocks.

Contact Person: David Meiselman

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GPSC Docket No. 31958

Staff Data Request STF-TAI-2-19 Follow-up

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

In response to data request STF-TAI-2-19 Follow-up, in Georgia Public Service Commission Docket No. 31958, Georgia Power Company ("Georgia Power") has submitted forecasted RTP kWh prices and sales for 2011 (the "Information"). The Information is trade secret of the Southern Company, Georgia Power, and its affiliates (the "Company").

The Information provided constitutes detailed information regarding GPC's costs and operations. If revealed to the public, a generation wholesaler, other public utility or power marketer could determine pricing/dispatch patterns and use the information to tailor purchased power offerings that could undermine the Company's market position. This could artificially drive up purchased power prices, costing the Company and its customers more than would have been the case had the information been kept confidential. These suppliers/competitors are not required to make similar information regarding their price publicly available.

The Information derives economic value from not being generally known to nor readily ascertainable by proper means by other persons or companies who can obtain economic value from its disclosure or use. The information is subject to extensive efforts to maintain its confidentiality. Additionally, the Information is subject to extensive efforts to maintain its secrecy.

Only select Company personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. If parties outside the Company are granted access to the Information, they would be required to sign confidentiality agreements with respect to the Information.

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-19 Follow-up

Question:

With regard to STF-TAI-2-19 that requested detailed calculations showing the determination of each RTP base revenue component for CBL, Incremental and Fuel Revenue, please explain and provide all analyses and calculations supporting the hard keyed RTP base revenues provided in the Confidential Excel spreadsheets. As a result of discussions with Georgia Power on September 2, 2010, it was represented that monthly forecasted RTP revenue was determined by multiplying forecasted MWH sales by forecasted monthly RTP prices. If this understanding is correct, please provide all details supporting the forecasted monthly RTP prices and indicate exactly what assumptions were made in developing forecasted monthly RTP prices as well as an explanation and quantification of each component within the total RTP price (as used by Georgia Power in its forecast).

Response:

See Attachment STF-TAI-2-19F-A for a detailed summary of the RTP price forecasting methodology.

Attachments STF-TAI-2-19F-B and STF-TAI-2-19F-C contain spreadsheets that display the outputs of the RTP price forecast for 2011 by each of the 5 components of RTP prices for the RTP-HA, and RTP-DA tariffs, respectively. These components can be found, by hour, in columns F through J of the spreadsheets. Column L of each spreadsheet contains forecasted kWh sales, and columns N and O contain the dollar amount forecasted to be collected in each hour for the generation component of the RTP price. The total amount can be found in cell O8769.

Please note, due to the voluminous nature of the requested information, Attachments STF-TAI-2-19F-B and C are submitted in electronic format on CD.

Contact Person: David Meiselman

Attachment STF-TAI-2-19F-A

RTP Forecasting Process

RTP price forecasting starts with an Energy Budget case from ProSym (production cost simulation model licensed from Ventyx), with a corresponding set of marginal costs (lambdas). From this ProSym Energy Budget case, a family of cases are produced with varying weathers (39 historical years are simulated) and varying fuel prices (7 for each historical weather pattern), yielding 273 distinctly different cases to analyze volatility associated with each component. The marginal costs (dependent variables) are passed along with the driving variables (independent variables) into neural net modeling to produce a model to predict variability of marginal costs associated with fuel price and load (weather) volatility. The resulting neural net models are benchmarked to match the ProSym results for the Energy Budget case as well as the 273 simulation runs. The neural net modeling allows for Monte Carlo iterations (equally likely scenario draws) to be relatively easily converted into hourly marginal price forecasts. This produces the full distribution (generally 1000 iterations) of hourly marginal costs to incorporate into an RTP price forecast for up to 10 years into the future.

In addition to the hourly marginal cost forecast, the hourly price components for transmission and generation capacity recovery are simulated hourly for each of the scenarios. For transmission, the hourly temperature and load as compared to the load forecast are used hourly with the forecasted carrying cost for marginal transmission to produce hourly transmission components to the price for each forecast year. The expected (average) recovery of transmission is set across all Monte Carlo iterations to match the forecasted carrying cost of transmission for each forecast year. For capacity recovery, the hourly load and the marginal capacity cost forecast (market price of capacity in the near term, carrying cost of Combustion Turbine technology in the longer term) is used to simulate hourly generation shortage components. The expected (average) recovery of capacity is set across all Monte Carlo iterations to match the market price of capacity in the near term and the carrying cost of combustion turbines in the longer term.

Once the hourly components for the lambda (marginal cost), transmission, and capacity components are developed, the appropriate losses and risk adders are applied for either the day-ahead or hour-ahead price to produce the full distribution of hourly price forecasts for both the day-ahead and hour-ahead rates.

To predict RTP revenue, the median price stream (50 percent probability that resulting annual price will be lower than median, 50 percent probability that resulting annual price will be higher than median) for each year is selected from the 1000 simulations. For both day-ahead and hour-ahead rates, this price is averaged monthly and multiplied by the projected monthly energies to yield monthly revenue forecasts for each year of the forecast window.

Attachments STF-TAI-2-19F-B & C

Due to the voluminous nature of the requested information, Attachments STF-TAI-2-19F-B and C are submitted in electronic format on CD.

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-20

Question:

Please explain and quantify exactly how the proposed change in the RTP generation reliability capacity component was calculated, determined, and quantified within M.F.R. Item F-4. Please provide analyses in electronic (Excel) format. Include examples at different actual peak demand levels.

Response:

The proposed methodology for the reliability capacity component included in M.F.R. Item F-4 is designed to recover approximately $10.5 million. See the Company's response to STF-TAI-2-21 for the related calculation and quantification as well as examples of different peak demand levels.

Contact Person: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2
TRADE SECRET

STF-TAI-2-20 Follow-up

Question:

With regard to STF-TA-2-20, that requested an explanation and quantification of exactly how the proposed change in the RTP generation capacity component was calculated, as well as STF-TAI-2-21 that requested the analyses and forecast that supports the $10.5 million increase in revenues from the RTP generation reliability capacity component, Georgia Power responded that this revenue is a result of a marginal capacity cost of $6.00 per KW-year. Please provide all analyses, studies, regression models, etc. showing exactly how this $6.00 was calculated; i.e., please provide in sufficient detail to replicate the $6.00 given Georgia Power's methodology, Marginal Peaker cost, excess reserve margins, wholesale market prices, etc.

Response:

The marginal capacity cost of $6.00 per KW-year used in determining the revenue impact of the RTP generation reliability capacity component was calculated using the following methodology. The underlying basis of this analysis was developed several years ago to determine the fundamental relationship between reserve margins and capacity prices. Once this fundamental supply and demand relationship was determined, factors have been escalated over time to reflect current capacity values associated with various levels of reserve margin.

1. Historical reserve margins were collected for the Southeastern Subregion of the SERC Reliability Corporation ("SERC"), formerly Southeastern Electric Reliability Council, for 1999 to 2007 for the peak summer months (May through September). Please reference cells E8 through E17 of Attachment STF-TAI-2-20 Follow-up.
2. Historical Forward Prices were collected for the Southeastern Subregion of SERC for 1999 to 2007 for the peak summer months. Please reference cells F8 through F17 Attachment STF-TAI-2-20 Follow-up.
3. The energy portion was extracted from each forward price to yield the capacity value for the month. (Capacity Price = Forward Price – (lesser of Energy Price or Lambda); Energy Price = (Gas Price * CT Heat Rate) + CT Variable O&M)
4. The capacity value was escalated to 2007$ using actual construction escalation rates.
5. The peak summer capacity value was then converted to an annual capacity price for the study period year using monthly capacity worth factors.
6. Historical monthly weather patterns and EFOR for the study period were analyzed and adjustment factors were applied to the capacity price based upon weather and EFOR for the study period.

TRADE SECRET

GEORGIA POWER COMPANY
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TRADE SECRET

7. A regression analysis was performed on the historical reserve margins from step 1 and the capacity prices calculated in steps 2 - 6. See Attachment STF-TAI-2-20 Follow-up to review the detailed results of the regression analysis performed.
6. The relationship between reserve margins and capacity prices from step 7 was used with the projected reserve margins for the Southeastern Subregion of SERC to develop the marginal capacity price. These prices were then escalated to 2011 using the Spring 2009 projected U.S. gross domestic product implicit price deflator. Please reference cells B20 through B26 of the Attachment STF-TAI-2-20 Follow-up.

Contact Person: David Meiselman

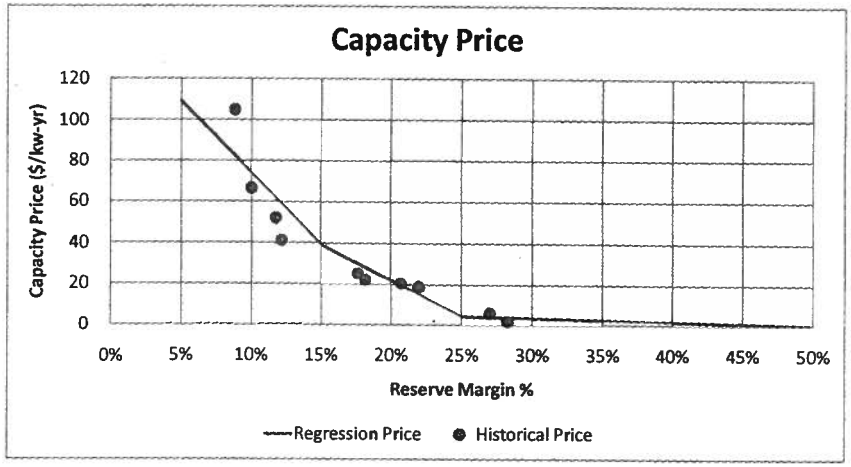
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Georgia Power Company's 2010 Rate Case
STF-TAI-2-20F

TRADE SECRET

		Step 1	Steps 2-6
		Reserve margin	Historical Price
Day Ahead Strip minus Lambda July & Aug	1999	8.80%	$105.00
From steps 2 - 6 of Described Methodology	2001	9.99%	$66.23
From steps 2 - 6 of Described Methodology	1999	11.74%	$51.83
From steps 2 - 6 of Described Methodology	2000	12.15%	$41.17
From steps 2 - 6 of Described Methodology	2003	17.67%	$25.32
From steps 2 - 6 of Described Methodology	2007	18.18%	$22.22
From steps 2 - 6 of Described Methodology	2004	20.70%	$20.44
From steps 2 - 6 of Described Methodology	2005	22.00%	$18.77
Actual Southern Market minus Lambda	2006	27.02%	$6.02
Actual Southern Market minus Lambda	2005	28.28%	$1.84

Step 8	2011	
Load Forecast (MW)	50,003	
Capacity (MW)	62,343	
Reserve Margin (%)	24.68%	
Capacity Price Assoc. with 24.68% RM	$5.69	(reference cell I2476)
Cumulative GDPIPD	1.06	
Capacity Price	$6.00	

Step 7	
Regression Price Details	
% Reserve	Price
0	
0.01	
0.02	
0.03	
0.04	
0.05	
0.06	
0.07	
0.08	
0.09	
0.1	
0.11	
0.12	
0.13	
0.14	
0.15	
0.16	
0.17	
0.18	
0.19	
0.2	
0.21	
0.22	
0.23	
0.24	
0.25	
0.26	
0.27	
0.28	
0.29	
0.3	
0.31	
0.32	
0.33	



	Step 7	
	Reserve margin	Regression Price
5%	0% to 5%	108.96
10%	5% to 10%	74.21
15%	10% to 15%	39.46
20%	15% to 20%	21.98
25%	20% to 25%	4.50
30%	25% to 30%	3.70
35%	30% to 35%	2.90
40%	35% to 40%	2.10
45%	40% to 45%	1.30
50%	45% to 50%	0.50

TRADE SECRET

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2
PUBLIC DISCLOSURE

STF-TAI-2-20 Follow-up

Question:

With regard to STF-TA-2-20, that requested an explanation and quantification of exactly how the proposed change in the RTP generation capacity component was calculated, as well as STF-TAI-2-21 that requested the analyses and forecast that supports the $10.5 million increase in revenues from the RTP generation reliability capacity component, Georgia Power responded that this revenue is a result of a marginal capacity cost of **$REDACTED** per KW-year. Please provide all analyses, studies, regression models, etc. showing exactly how this **$REDACTED** was calculated; i.e., please provide in sufficient detail to replicate the **$REDACTED** given Georgia Power's methodology, Marginal Peaker cost, excess reserve margins, wholesale market prices, etc.

Response:

REDACTED

Contact Person: David Meiselman

PUBLIC DISCLOSURE

Docket No. 31958
Georgia Power Company's 2010 Rate Case
STF-TAI-2-20F

PUBLIC DISCLOSURE

		Step 1	Steps 2-6
		Reserve margin	Historical Price
Day Ahead Strip minus Lambda July & Aug	1999	REDACTED	
From steps 2 - 6 of Described Methodology	2001		
From steps 2 - 6 of Described Methodology	1999		
From steps 2 - 6 of Described Methodology	2000		
From steps 2 - 6 of Described Methodology	2003		
From steps 2 - 6 of Described Methodology	2007		
From steps 2 - 6 of Described Methodology	2004		
From steps 2 - 6 of Described Methodology	2005		
Actual Southern Market minus Lambda	2006		
Actual Southern Market minus Lambda	2005		

Step 8		2011
Load Forecast (MW)		REDACTED
Capacity (MW)		
Reserve Margin (%)		
Capacity Price Assoc. with	RM	
Cumulative GDPIPD		
Capacity Price		

(reference cell I2476)

Step 7	
Regression Price Details	
% Reserve	Price
REDACTED	

Step 7		
	Reserve margin	Regression Price
5%	0% to 5%	
10%	5% to 10%	
15%	10% to 15%	
20%	15% to 20%	
25%	20% to 25%	
30%	25% to 30%	
35%	30% to 35%	
40%	35% to 40%	
45%	40% to 45%	
50%	45% to 50%	

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-21

Question:

Please provide the Company's analysis and forecast that supports the $10.5 million in increase revenues from the RTP reliability component.

Response:

The proposed methodology for the Reliability Capacity Component is not designed to increase revenues, only to send appropriate price signals to reflect revenue already included in the budget. See Attachment STF-TAI-2-21 on CD for the hourly data analysis that supports the estimated $10.5 million revenue recovery in 2011 from the redesigned RTP Reliability Capacity Component. The calculations are based on hourly forecasted system loads and projected RTP-DA and RTP-HA kWh for 2011.

Contact Person: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-21 Follow-up – TRADE SECRET

Question:

Please provide the historical capacity cost (per KW-year) for each of the last 10 years the and the projected capacity cost per KW-year for the years 2012-2015 corresponding to the $6.00/KW per year provided in response to STF-TAI-2-21.

Response:

The following amounts are shown in $/kW-yr.

2001 – 20.65
2002 – 12.90
2003 – 5.00
2004 – 8.00
2005 – 10.22
2006 – 13.81
2007 – 14.80
2008 – 12.60
2009 – 19.22
2010 – 6.95

2011 – 6.00
2012 – 10.14
2013 – 23.17
2014 – 34.00
2015 – 44.83

Contact Person: David Meiselman

TRADE SECRET

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-21 Follow-up – PUBLIC DISCLOSURE

Question:

Please provide the historical capacity cost (per KW-year) for each of the last 10 years the and the projected capacity cost per KW-year for the years 2012-2015 corresponding to the $**REDACTED**/KW per year provided in response to STF-TAI-2-21.

Response:

The following amounts are shown in $/kW-yr.

2001 – 20.65
2002 – 12.90
2003 – 5.00
2004 – 8.00
2005 – 10.22
2006 – 13.81
2007 – 14.80
2008 – 12.60
2009 – 19.22
2010 – 6.95

2011 –REDACTED
2012 –REDACTED
2013 –REDACTED
2014 –REDACTED
2015 –REDACTED

Contact Person: David Meiselman

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-22

Question:

With respect to the direct testimony of Gregory Roberts, page 11, line 6 through page 12, line 12, please provide a detailed explanation of how the reliability capacity component will be calculated; and, how the cost of this component will be based on the market value of capacity in the near term, and the economic carrying cost of a combustion turbine in the long term. In this response please quantify all aspects of the requested information. Please provide examples of this calculation for three different actual peak loads that each trigger a different level for the generation reliability capacity component.

Response:

The reliability capacity component of RTP will be calculated using the following formula:

$$\text{Max } [0, ((\text{Load}_{\text{Hour}} / \text{Projected Peak Load}_{\text{Year}}) - \text{Capacity Threshold}_{\text{Year}}))]$$

$$\text{X } (\text{Capacity Cost}_{\text{Year}} / \text{Capacity Sum Response Function}_{\text{Year}})$$

Starting in 2011, the Capacity Threshold = 0.948 and the Capacity Sum Response Function = 0.966. The Capacity Cost will be based on the market value of capacity.

Regarding the cost component of this algorithm, the use of the market value of capacity versus the economic carrying cost ("ECC") of a Combustion Turbine ("CT") was based on the determination of the equilibrium year for the Southeast Sub-region of the Southeastern Electric Reliability Council ("SERC") which is 2018. Prior to 2018, the market value of capacity is less than the ECC of a CT and in 2018 the value of the two options is the same. Therefore, the market value of capacity was used in the algorithm.

See the Company's response to STF-TAI-2-21 for calculations of reliability capacity component amounts based on forecasted loads and projected RTP-DA and RTP-HA kWh for 2011.

Contact Person: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-23

Question:

With respect to the direct testimony of Gregory Roberts, page 12, line 17 through page 13, line 13; please provide all analyses supporting the estimated $45 million increase to base revenues as a result of the proposed change. Please provide all analyses in hardcopy and electronic (ASCII or Excel) format.

Response:

See Attachment STF-TAI-2-23. Due to the voluminous nature of the information requested, only a summary page is being provided in hardcopy. All other information is being provided in an electronic version only.

Contact Person: David Meiselman

TRADE SECRET

Attachment STF-TAI-2-23 TS.xlsx - TRADE SECRET - Estimated RTP Fuel Accounting Impact for 2011

Calculated Composite for Projected FCR Factors (¢/kWh)

Amortization Period: 42

Part B Summer Factor for 42 Months:

Transmission	0.0413
Primary	0.3153
Secondary	0.3204

	DA MWh	DA Cust %	Weighted DA Part B Factor	HA MWh	HA Cust %	Weighted HA Part B Factor
	3,337,999	24.92%	0.0776	9,848,724	83.24%	0.2591
	3,625,734	27.07%	0.0854	1,773,520	14.99%	0.0473
	6,428,661	48.00%	0.1538	209,172	1.77%	0.0057
Total	13,392,394	100.00%	0.3168	11,831,416	100.00%	0.3121

Part B Winter Factor for 42 Months:

Transmission	0.1555
Primary	0.1575
Secondary	0.1600

	DA MWh	DA Cust %	Weighted DA Part B Factor	HA MWh	HA Cust %	Weighted HA Part B Factor
	3,337,999	24.92%	0.0388	9,848,724	83.24%	0.1294
	3,625,734	27.07%	0.0426	1,773,520	14.99%	0.0236
	6,428,661	48.00%	0.0768	209,172	1.77%	0.0028
Total	13,392,394	100.00%	0.1582	11,831,416	100.00%	0.1559

	RTP-DA	RTP-HA
Trans. Level B2	86,248	286,642
Trans. Level C	2,089,956	8,658,420
Trans. Level D	168,971	339,799
Trans. Level E	992,825	563,863
Prim. Level F	3,625,734	1,773,520
Sec. Level G	6,428,661	209,172
MWh Totals	13,392,394	11,831,416

Trans. Totals	3,337,999	9,848,724

Energy Data Source: GPC MWH Sales by Rate & Level - 12 Months Ending December 31, 2009.

	Based on 42 Month Amortization							
Month	Proposed Transmission Factors	Proposed Primary Factors	Proposed Secondary Factors	RTP-DA FCR Composite	RTP-HA FCR Composite	Mon	RTP-DA Part B FCR Composite	RTP-HA Part B FCR Composite
2011-01	4.0758	4.1281	4.1949	4.1471	4.0857	10	0.1582	0.1559
2011-02	4.0758	4.1281	4.1949	4.1471	4.0857	11	0.1582	0.1559
2011-03	4.0758	4.1281	4.1949	4.1471	4.0857	12	0.1582	0.1559
2011-04	4.0758	4.1281	4.1949	4.1471	4.0857	13	0.1582	0.1559
2011-05	4.0758	4.1281	4.1949	4.1471	4.0857	14	0.1582	0.1559
2011-06	4.5689	4.6276	4.7024	4.6489	4.5801	15	0.3168	0.3121
2011-07	4.5689	4.6276	4.7024	4.6489	4.5801	16	0.3168	0.3121
2011-08	4.5689	4.6276	4.7024	4.6489	4.5801	17	0.3168	0.3121
2011-09	4.5689	4.6276	4.7024	4.6489	4.5801	18	0.3168	0.3121
2011-10	4.1920	4.2458	4.3145	4.2654	4.2022	19	0.1582	0.1559
2011-11	4.1920	4.2458	4.3145	4.2654	4.2022	20	0.1582	0.1559
2011-12	4.1920	4.2458	4.3145	4.2654	4.2022	21	0.1582	0.1559

TRADE SECRET

PUBLIC DISCLOSURE

Attachment STF-TAI-2-23 TS.xlsx - PUBLIC DISCLOSURE - Estimated RTP Fuel Accounting Impact for 2011

Calculated Composite for Projected FCR Factors (¢/kWh) | **Amortization Period:** 42

Part B Summer Factor for 42 Months:

		DA MWh	DA Cust %	Weighted DA Part B Factor	HA MWh	HA Cust %	Weighted HA Part B Factor
Transmission	REDACTED	3,337,999	24.92%	REDACTED	9,848,724	83.24%	REDACTED
Primary	REDACTED	3,625,734	27.07%	REDACTED	1,773,520	14.99%	REDACTED
Secondary	REDACTED	6,428,661	48.00%	REDACTED	209,172	1.77%	REDACTED
	Total	13,392,394	100.00%	REDACTED	11,831,416	100.00%	REDACTED

Part B Winter Factor for 42 Months:

		DA MWh	DA Cust %	Weighted DA Part B Factor	HA MWh	HA Cust %	Weighted HA Part B Factor
Transmission	REDACTED	3,337,999	24.92%	REDACTED	9,848,724	83.24%	REDACTED
Primary	REDACTED	3,625,734	27.07%	REDACTED	1,773,520	14.99%	REDACTED
Secondary	REDACTED	6,428,661	48.00%	REDACTED	209,172	1.77%	REDACTED
	Total	13,392,394	100.00%	REDACTED	11,831,416	100.00%	REDACTED

	RTP-DA	RTP-HA
Trans. Level B2	86,248	286,642
Trans. Level C	2,089,956	8,658,420
Trans. Level D	168,971	339,799
Trans. Level E	992,825	563,863
Prim. Level F	3,625,734	1,773,520
Sec. Level G	6,428,661	209,172
MWh Totals	13,392,394	11,831,416

Trans. Totals	3,337,999	9,848,724

Energy Data Source: GPC MWH Sales by Rate & Level - 12 Months Ending December 31, 2009.

	Based on 42 Month Amortization							
Month	Proposed Transmission Factors	Proposed Primary Factors	Proposed Secondary Factors	RTP-DA FCR Composite	RTP-HA FCR Composite	Mon	RTP-DA Part B FCR Composite	RTP-HA Part B FCR Composite
2011-01	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	10	REDACTED	REDACTED
2011-02	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	11	REDACTED	REDACTED
2011-03	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	12	REDACTED	REDACTED
2011-04	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	13	REDACTED	REDACTED
2011-05	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	14	REDACTED	REDACTED
2011-06	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	15	REDACTED	REDACTED
2011-07	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	16	REDACTED	REDACTED
2011-08	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	17	REDACTED	REDACTED
2011-09	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	18	REDACTED	REDACTED
2011-10	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	19	REDACTED	REDACTED
2011-11	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	20	REDACTED	REDACTED
2011-12	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	21	REDACTED	REDACTED

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-24

Question:

Please explain why no increase is proposed for the non-fuel incremental RTP rates.

Response:

By definition, the incremental RTP prices are designed to send price signals reflecting the marginal costs of generation and transmission as customers take service. They are not designed to recover embedded costs. Therefore, the Company has not proposed, and it would be inappropriate, to assign test-year-based embedded costs to the incremental RTP portion of a customer's rate.

Contact Person: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-27

Question:

With respect to the direct testimony of Gregory Roberts, page 17, lines 26 through 29, please explain the proposed modifications for making adjustments in CBL levels.

Response:
This section of testimony refers to the proposed language modifications in the RTP tariffs. They are for clarification purposes only and do not affect the way adjustments are currently made to CBL levels. The language change is shown in the RTP tariffs included in MFR-F1.

Contact Person: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-30

Question:

For the TOU-PEV-1 tariff, will the tariff rate apply to all of the customer's usage?

Response:

Yes, the TOU-PEV-1 tariff will apply to all of the customer's usage.

Contact: David Meiselman

GEORGIA POWER COMPANY
Docket No. 31958
Staff Data Request No STF-TAI-2

STF-TAI-2-31

Question:

Will Georgia Power verify that a customer has an electric vehicle prior to a customer being placed on the TOU-PEV-1 tariff? If not, why not?

Response:

No. Georgia Power will not verify that a customer has an electric vehicle before the customer is placed on TOU-PEV-1. The rate is designed so that customers with an electric vehicle can save money on the new rate over the R or TOU-REO rates. Customers without electric vehicles would have no incentive to go on the TOU-PEV rate.

Contact: David Meiselman