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FPSC - COMMISSION CLERK

August 30, 2018

Takira Thompson
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: 20180000-OT (Undocketed filing for 2018) – Supplemental Data Request #2

Dear Ms. Thompson,

Gainesville Regional Utilities hereby submits its response to PSC Staff's Supplemental Data Request #2. I have also emailed this response to tthompso@psc.state.fl.us.

Sincerely,

/s/Jamie Verschage
Managing Analyst
Gainesville Regional Utilities (GRU)

GAINESVILLE REGIONAL UTILITIES' RESPONSES TO SUPPLEMENTAL DATA REQUEST #2

1. With respect to the forecasting methodology, procedures, and models developed associated with Winter and Summer Peak Demand, please specify all the differences/ modifications/ improvements, if any, between what used in Gainesville Regional Utilities' (GRU) 2017 and 2018 Ten Year Site Plans (TYSP).

   The methodology used to develop GRU's load forecast for the 2018 TYSP is the same methodology used to develop GRU's load forecast for the 2017 TYSP.

2. For its 2018 TYSP, please identify and explain the measures and/or criteria, if any, GRU used to ensure the models of peak demand adequately explain historical variations and to enhance its forecasting accuracy.

   GRU employs a load factor methodology for producing demand forecasts from projections of net energy for load. The overall forecasting process is a bottom-up approach with models for usage per customer and number of customer by major customer class. The efforts to develop the models that best explain historical variance reside in these usage per customer and number of customers equations, and they include minimizing the mean squared error for each equation, ensuring that each variable included contributes significantly and possesses the appropriate sign, and minimizing patterns in historical error terms. Consistency in forecasting methodology from year to year combined with more than 30 years' experience of staff performing the forecasting work also contribute to enhancing forecast accuracy.

3. Please identify and explain the new measures, if any, GRU used to address the uncertainty inherent in the process of peak demand forecasting for its 2018 TYSP.

   GRU routinely assesses the accuracy of its historical load forecast using an "error fan" analysis comparing actual net energy for load and summer peak demand against our forecasts over the past 5, 10, and 20 years. Due to the high penetration of natural gas in GRU's service area, GRU is consistently a summer peaking system and this analysis has not been conducted for winter peak demand forecasts. Over the past 10 years (2009-2018), the average forecast error for summer peak demand forecasts was -3.6%. Over the past five years (2014-2018), the average forecast error was -3.3%. A negative forecast error means that projected values were greater than actual values. Over the past 10 years (2008-2017), the average forecast error of net energy for load was -4.9%, and from 2013-2017 it was +0.1%. The standard deviation of historical forecast error can be used to develop probabilistic high or low bands around the base case forecast.

4. Please provide the Historical Forecast Accuracy associated with GRU's Winter Peak Demand for the period 2012/2013 through 2016/2017 and Summer Peak Demand for the period 2013 through 2017.

Table 1. Accuracy of GRU's Winter Peak Demand Forecasts

	Winter Retail Peak Demand Forecast Error Rate (%)					Average
	Forecasting Period Prior					
	5	4	3	2	1	
	2008 TYSP	2009 TYSP	2010 TYSP	2011 TYSP	2012 TYSP	
2012 / 2013 actual	326	326	326	326	326	
2012 / 2013 forecast	367	323	323	318	319	
actual vs forecast	-11%	1%	1%	3%	2%	-1%
	2009 TYSP	2010 TYSP	2011 TYSP	2012 TYSP	2013TYSP	
2013 / 2014 actual	325	325	325	325	325	
2013 / 2014 forecast	323	326	321	320	315	
actual vs forecast	1%	0%	1%	2%	3%	1%
	2010 TYSP	2011 TYSP	2012 TYSP	2013TYSP	2014 TYSP	
2014 / 2015 actual	324	324	324	324	324	
2014 / 2015 forecast	330	324	320	316	315	
actual vs forecast	-2%	0%	1%	3%	3%	1%
	2011 TYSP	2012 TYSP	2013 TYSP	2014 TYSP	2015 TYSP	
2015 / 2016 actual	313	313	313	313	313	
2015 / 2016 forecast	326	322	317	318	316	
actual vs forecast	-4%	-3%	-1%	-2%	-1%	-2%
	2012 TYSP	2013 TYSP	2014 TYSP	2015 TYSP	2016 TYSP	
2016 / 2017 actual	326	326	326	326	326	
2016 / 2017 forecast	322	319	321	319	322	
actual vs forecast	1%	2%	2%	2%	1%	2%

Overall forecast error (positive error reflects under-forecasting) **0.2%**

Table 2. Accuracy of GRU's Summer Peak Demand Forecasts

	Summer Retail Peak Demand Forecast Error Rate (%)					Average
	Forecasting Period Prior					
	5	4	3	2	1	
	2008 TYSP	2009 TYSP	2010 TYSP	2011 TYSP	2012 TYSP	
2013 actual	391	391	391	391	391	
2013 forecast	449	396	396	401	401	
actual vs forecast	-13%	-1%	-1%	-2%	-2%	-4%
	2009 TYSP	2010 TYSP	2011 TYSP	2012 TYSP	2013TYSP	
2014 actual	383	383	383	383	383	
2014 forecast	398	398	404	401	389	
actual vs forecast	-4%	-4%	-5%	-4%	-2%	-4%
	2010 TYSP	2011 TYSP	2012 TYSP	2013TYSP	2014 TYSP	
2015 actual	384	384	384	384	384	
2015 forecast	399	407	402	389	391	
actual vs forecast	-4%	-6%	-4%	-1%	-2%	-3%
	2011 TYSP	2012 TYSP	2013 TYSP	2014 TYSP	2015 TYSP	
2016 actual	390	390	390	390	390	
2016 forecast	410	404	391	395	389	
actual vs forecast	-5%	-3%	0%	-1%	0%	-2%
	2012 TYSP	2013 TYSP	2014 TYSP	2015 TYSP	2016 TYSP	
2017 actual	380	380	380	380	380	
2017 forecast	405	393	400	393	395	
actual vs forecast	-6%	-3%	-5%	-3%	-4%	-4%

Overall forecast error (negative error reflects over-forecasting) **-3.5%**

5. Please refer to Schedule 7.1 of GRU's 2018 TYSP and GRU's response to question 27 of staff's Supplemental Data Request #1. Is the Solar FIT program's contracted firm summer capacity of 6.5 MW included in Schedule 7.1 of the TYSP? If so, please identify where this capacity is accounted for. If not, why not?

GRU's Solar FIT program's capacity is not included in Schedule 7.1. GRU has more than 250 Solar FIT installations within its service territory, and unlike GRU's other generation resources, GRU does receive real-time information on these systems' power output. These systems feed energy into GRU's system at distribution-level voltage and are not part of GRU's generation energy management system. From GRU's planning and operations perspectives, these systems have the effect of lowering GRU's generation demand (akin to net-metered PV systems). This is reflected in GRU's low system losses and is believed to reduce system losses by 1.1%-1.2% per year. Solar FIT output is "as available" energy and GRU does not have the ability to dispatch it.

6. Please refer to Schedules 1 and 7.2 of GRU's 2018 TYSP. Why does the total installed winter capacity for the years 2018/2019 through 2021/2022 seen in Schedule 7.2 reflect a different system total net generation capability than as reported in column 15 of Schedule 1?

GRU's Ten-Year Site Plan is compiled in Microsoft Word with links to Microsoft Excel tables. It appears that GRU's Ten-Year Site Plan submitted to the PSC contained an outdated link to Schedule 7.2. GRU apologizes for this error. A revised Schedule 7.2 is attached to this document.

REVISED SCHEDULE 7.2

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (2) MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand (1) MW	Reserve Margin before Maintenance MW	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance (1) MW	Reserve Margin after Maintenance (1) % of Peak
2008/09	634	76	0	0	711	421	290	68.8%	0	290	68.8%
2009/10	628	76	0	0	704	464	240	51.8%	0	240	51.8%
2010/11	628	53	0	0	680	409	271	66.4%	0	271	66.4%
2011/12	630	52	0	0	682	371	311	83.8%	0	311	83.8%
2012/13	618	52	0	0	670	348	322	92.5%	0	322	92.5%
2013/14	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2014/15	550	106	0	0	656	360	296	82.1%	0	296	82.1%
2015/16	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2016/17	554	106	0	0	660	360	299	83.1%	0	299	83.1%
2017/18	659	4	0	0	663	366	297	81.3%	0	297	81.3%
2018/19	659	4	0	0	663	359	304	84.9%	0	304	84.9%
2019/20	659	4	0	0	663	362	301	83.4%	0	301	83.4%
2020/21	659	4	0	0	663	365	299	81.9%	0	299	81.9%
2021/22	659	4	0	0	663	367	296	80.5%	0	296	80.5%
2022/23	584	4	0	0	588	370	218	58.8%	0	218	58.8%
2023/24	584	0	0	0	584	373	211	56.6%	0	211	56.6%
2024/25	584	0	0	0	584	376	209	55.5%	0	209	55.5%
2025/26	584	0	0	0	584	379	206	54.4%	0	206	54.4%
2026/27	562	0	0	0	562	381	181	47.5%	0	181	47.5%
2027/28	540	0	0	0	540	384	156	40.7%	0	156	40.7%

(1) System Peak demands shown in this table reflect service to partial and full requirements wholesale customers.

(2) Details of planned changes to installed capacity from 2018-2027 are reflected in Schedule 8.

7. Please provide a comparison of GRU's 2017 and 2018 TYSPs, identifying any notable differences.

   The most notable differences between GRU's 2017 and 2018 TYSPs are due to GRU's acquisition of Deerhaven Renewable, a 102.5-MW biomass generating facility, in November 2017. GRU previously received energy under a purchase power agreement with this generation facility, previously known as the Gainesville Renewable Energy Center. GRU's 2018 TYSP was modified from its 2017 TYSP to include a discussion on biomass fuel prices (section 2.5.3).

   In addition, GRU put a 7.4-MW reciprocating natural gas-fired engine into service in December 2017. This machine was installed in a distributed generation combined heat-and-power application that serves an academic medical complex. This machine was listed as a planned generation addition in Schedule 9 of GRU's 2017 TYSP; Schedule 9 was removed from GRU's 2018 TYSP since this unit was placed into generation and no other units are currently planned.

8. Has GRU taken solar capacity degradation into account in its planning process? If so, please explain how degraded capacity values are calculated, what assumptions are required for calculating degraded capacity values, if solar degradation is taken into account in GRU's cost-effectiveness evaluations, and what causes solar capacity degradation. If not, why not?

   GRU has not taken solar capacity degradation into account in its planning process thus far, although GRU estimates degradation to be at most 1% per year. Over the 10-year planning horizon, the impact to GRU's electric system from degradation of existing PV systems connect to GRU's system is estimated to be minute.