Gulf Power

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VIA ELECTRONIC FILING

Ms. Carlotta Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition for rate increase by Gulf Power Company, Docket No. 160186-EI

Dear Ms. Stauffer:

Attached is the Rebuttal Testimony of Gulf Power Company Witness Michael T. O'Sheasy.

(Document 12 of 16)

Sincerely,

Robert L. McGee, Jr.

Robert L. McGee, Jr.
Regulatory & Pricing Manager

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160186-EI

Gulf Power

REBUTTAL TESTIMONY

OF

MICHAEL T. O'SHEASY

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Michael T. O'Sheasy
Docket No. 160186-EI
In Support of Rate Relief
Date of Filing: February 8, 2017

Q. Please state your name, business address and occupation.

A. My name is Mike O'Sheasy. My business address is 5001 Kingswood Drive, Roswell, Georgia 30075. I am a Vice President with Christensen Associates, Inc.

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I rebut the testimony of Witness Rábago (Southern Alliance for Clean Energy and the League of Women Voters of Florida) and Witness Alderson (Federal Executive Agencies) related to cost of service issues.

Q. Please outline your rebuttal of Mr. Rábago.

A. First, I correct several mistakes in Mr. Rábago's critique of the Minimum Distribution System (MDS). Then I clarify why MDS is the appropriate methodology for classifying distribution costs and subsequently enables the most appropriate allocation of Gulf's distribution costs.

Second, I explain why a 1 non-coincident peak (1 NCP) allocator is the most appropriate allocator for apportioning Gulf's distribution demand-related costs to the various rate classes.

Q. Please outline your rebuttal of Ms. Alderson.

A. I explain why the best allocator for Gulf's production investment-related costs is 12 monthly coincident peak (12 MCP) & 1/13th energy, and not the 4 summer coincident peak (CP) or the 4 summer/1 winter CP methods she recommends.

I. Rábago MDS Testimony

Q. Mr. Rábago recommends that the Commission not approve the use of MDS. Do you agree with Mr. Rábago?

A. No. As I stated in my direct testimony, use of MDS for Gulf is an accurate, cost causative cost-of-service methodology. Additionally, Mr. Rábago has made several mistakes or mischaracterizations in coming to his conclusion regarding MDS.

Q. Please explain what you mean by mistakes or mischaracterizations.

A. Throughout his testimony, Mr. Rábago refers to a change from the present rates for the residential revenue requirement. He states that this change was caused by two major factors: first, a change to using MDS in the allocation process (p. 4, lines 15-22), and second, the introduction of the Advanced Pricing Package.

Q. Is Gulf's use of MDS in the allocation process a change as Mr. Rábago asserts?

A. No. Gulf's present rates and present revenues are based on the MDS methodology. Both the present rates and present revenues shown in Gulf's recommended cost-of-service study provided in Exhibit MTO-2 are based upon the use of the MDS. The cost-of-service study with the MDS was the study used in the Commission-approved Stipulation and Settlement Agreement in Gulf's last rate case, Docket No. 130140-EI. The MDS methodology was also included in a cost-of-service stipulation that was approved by this Commission in Gulf's prior rate case, Docket No. 110138-EI.

Q. Mr. Rábago claims that "through the cost allocation process, the Company proposes to increase the total revenue requirement assigned to the residential class by more than 20%, or more than $68 million." Is his assertion correct?

A. No. The proposed increase is $61 million as shown in Exhibit MTO-2, Schedule 1.10. Moreover, there is no change in cost allocation between the present revenue requirement (which is based upon Gulf's present rates) and the proposed revenue requirement (which is based on Gulf's proposed rates) for any of the rate classes.

Q. Mr. Rábago states that the change in residential revenue requirements is accomplished through use of a proposed minimum system method, as well as through increases in costs. Even though use of MDS is not new and is indeed used for current rates and revenue requirements, can you estimate the impact of using MDS or not using MDS for proposed rates?

A. Yes, the two versions shown on MFR E-6b can be used for such an estimation. By comparing the revenue requirement on line 13, column (4) of MFR E-6b, page 1 of 2 with MDS to page 2 of 2 without MDS, the difference would be $6,829,000. This amount is less than 2 percent of the residential rate class's overall revenue requirement.

Q. So, Gulf is not introducing a change to the cost-of-service methodology upon which present rates are based?

A. That is correct. Both Gulf's present rates and proposed rates are based on the use of MDS.

Q. Does MDS have a logical cost-causative foundation?

A. Yes. This is explained in my direct testimony beginning on page 17.

Q. Is MDS accepted by National Association of Regulatory Utility Commissioners (NARUC) as a reasonable methodology?

A. Yes.

Q. Is MDS commonly used by other utilities?

A. Yes. It is used by several nearby utilities, including all utilities in the Southern Electric system, Duke North Carolina, and South Carolina Electric and Gas (SCE&G), as well as other utilities in Florida.

Q. Mr. Rábago says that Professor James Bonbright (a respected utility economist and author) rejected the MDS. Do you agree with his characterization as a "rejection"?

A. No. In Professor Bonbright's often-referenced book *Principles of Public Utility Rates*, he opines that including a minimum-sized distribution system among the customer-related costs seems 'indefensible,' but he continues to add that it is even less reasonable to place them in demand-related costs. He therefore suggests that the MDS should be recognized "as a strictly unallocable portion of total costs." (Page 492) Despite Mr. Rábago's assertions otherwise, Professor Bonbright ultimately does not address where to place these costs in ratemaking.

II. Rábago 1 NCP Testimony

Q. Beginning on page 19 of his testimony, Mr. Rábago criticizes the use of the 1 NCP for primary and secondary distribution cost allocation. Why does Gulf use the 1 NCP?

A. To address this question, one needs to consider how Gulf decides upon the sizes and amount of equipment to install. Gulf makes these decisions by estimating the maximum loads that will need to be served at any time. This maximum loading may be different in size and occur at a different time for one circuit versus another, or even one line transformer versus another. The peak loading on these pieces of equipment does not occur when the system peaks. The system peaks are referred to as the system coincident peaks (CP). They drive production and transmission equipment costs but not distribution equipment costs. The peaks that drive primary and secondary distribution costs are best reflected by each rate class's maximum non-coincident peak demand for the year (1 NCP). Gulf's 1 NCP allocator considers that some equipment is driven by a rate class's specific peak. For instance, line transformers serving residential customers may be driven and sized for the incremental air-conditioning loads in the summer which cause the residential rate class peak.

Q. What about circumstances in which the equipment is being shared by multiple rate classes?

A. Because the 1 NCP allocator is comprised of multiple rate classes, it shares these costs amongst the rate classes.

Q. So, if different distribution equipment may be expected to have different individual peak demands that occur at different times, does Gulf track by asset the specific peak expectations, when they occur, and who will cause them?

A. No, and to my knowledge, no utility does so for cost allocation purposes. Instead, utilities and regulators have agreed over time to use an NCP that is based on the rate class or the individual customers as a proxy. In the NARUC *Electric Utility Cost Allocation Manual*, page 97, it explains, "Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities."

Q. Mr. Rábago proposes that this allocator approach overstates demand-related costs. Is Mr. Rábago correct?

A. No. Demand-related costs are whatever they are regardless of the allocator to the rate classes. The use of 1 NCP as an allocator for primary and secondary distribution costs has nothing to do with the amount of demand costs to be allocated. Moreover, the 1 NCP allocator does a good job of apportioning these demand costs amongst the rate classes in a fair manner, as inferred by NARUC's approval of the methodology.

Q. Has the 1 NCP by rate class methodology been used by Gulf for previous rate case filings?

A. Yes, at least as far back as rate case filings in the 1980's. It was used in Gulf's last rate filing in Docket No.130140-EI. The use of the 1 NCP allocator produces stable results and is an influencing factor in present rates.

Q. Does the fact that 1 NCP has been used in the past mean it must be used in the future?

A. No, not necessarily. A change in methodology, though, should be driven by compelling evidence that there is a better methodology. Having seen none, Gulf is convinced that 1 NCP is the best allocator for distribution demand costs.

Q. Mr. Rábago on page 35 of his testimony, line 9, suggests that modifying "the 1 NCP cost allocator would also reduce the volumetric charge for residential customers and thus the ultimate rate impact." Would this be a good idea?

A. No, the 1 NCP allocator is not in need of modification. Furthermore, one should not modify a cost-causative allocator because of a desired "ultimate rate impact." One should determine cost as accurately as possible and then decide on what is the desired/proposed rate impact via the rate design.

Q. Please summarize your rebuttal of Mr. Rábago.

A. The MDS has been Gulf's preferred and most cost-reflective methodology for dividing distribution costs into demand and customer-related. It was included in a stipulation approved by this Commission in Docket No. 110138-EI and was a component of the approved settlement of Gulf's last rate case Docket No. 130140-EI. MDS is commonly used by other utilities and approved for use by NARUC. We recommend its approval here.

Gulf has used 1 NCP by rate class for many years to allocate primary and secondary distribution costs, and it has been approved by this Commission in numerous dockets. It produces reasonable and stable results. It is the most practical cost-reflective allocator for Gulf's cost-of-service study. We recommend its approval here.

III. Alderson Production Cost Allocation

Q. Do you agree with Ms. Alderson's recommendation to adopt a production investment-related cost allocator using either the 4 summer coincident peak (CP) or 4 summer/1 winter CP method rather than 12 MCP & 1/13th energy allocator?

A. No, I do not. I think the 12 MCP and 1/13th energy is a superior allocator of production (generation) investment-related costs for Gulf.

Q. What is the premise of Ms. Alderson's recommendation to use 4 CP (or 4 CP/1 CP) for allocation of Gulf's production investment-related costs?

A. Her argument focuses upon the idea that the target reserve requirement should determine the selection of the production function allocator. Additionally, she claims that the target reserve requirement "ultimately is a formula calculated solely on the system's summer and winter peak demands." However, Gulf Power and the Southern electric system consider much more than the 4 summer and 1 winter peak load demands in setting the Company's reserve margin. In determining its optimal reserve margin, consideration is given to reliability risks in every hour of the year, even though the majority of the risk occurs during the summer and winter peak months. In fact, even though Gulf remains a summer peaking system, reliability risks are growing in the winter and shrinking in the summer. Also, because of necessary heavy scheduling of unit maintenance in the spring and fall and the risk of unplanned outages in those same seasons, reliability risks can be spread across a number of hours of the fall and spring seasons. Finally, I believe there are other factors such as cost minimization influences, allocator stability, fairness, and history of use, which should be considered when selecting the production investment-related allocator besides simply the reserve margin or the month's percent of annual system peak as shown in Ms. Alderson's Exhibit AMA-1.

Q. Please expand on why reliability risks are increasing in the winter and shrinking in the summer.

A. Winter peak loads, which occur primarily during the early morning hours, ramp-up more rapidly than do summer peak loads, which occur more often in the afternoon hours. These more rapidly-climbing winter peak loads create more reserve risks per MW of load between winter and those of summer. Additionally, increasing solar photovoltaic (PV) penetration, which may help serve summer afternoon peaks, provides little during early morning winter peaks. Lastly, forced outage rates on generation generally increase during the most extreme winter peaks due to the risks of freeze-ups of instrumentation and fuel issues during the extreme cold weather experienced in many winters.

Q. Did the Southern system peak for 2016 occur during the summer?
A. Yes, it did, but this was the first such occurrence since 2013.

Q. You mentioned that every hour is analyzed by system planning. Don't the summer months contain the majority of these hours of high reliability risk?
A. Not nearly so much as in the past. Reliability risks associated with a deficiency of generation to serve load at any given time vary throughout the year. Historically on the Southern electric system, about 85 percent of generation deficiency reliability risk fell during the summer months and 15 percent during the winter months. Over the last 10 or 15 years, there has been a gradual but growing dependence on natural gas-fired capacity, and in recent years on solar PV resources. Additionally, as customers' heating and air conditioning systems are changed out over time, the efficiency improvements in the new systems decrease demand on the summer peaks much more so than they reduce demand on the early morning winter peaks. With these combinations of changes, reliability risks are now closer to 50/50.

Q. If 4 CP using summer months fails to adequately address the growing reliability needs of winter, what do you think about 4 summer/1 winter?
A. A 4 summer/1 winter allocator fails to go far enough in capturing the reliability needs of Gulf Power. Besides the growing winter and shrinking summer reliability risks that I previously mentioned, one winter month is simply not enough winter months, in part because it is impossible to know which of the winter months will have the coldest temperatures and,

therefore, the highest winter loads. Furthermore, growing reliability needs in the winter months coupled with on-going summer constraints means that more and more scheduled maintenance will be squeezed into fall and spring seasons. Unit maintenance must be planned accordingly, which can result in unit availability less in non-peak seasons than peak seasons. The 12 MCP & 1/13th energy allocator will best reflect Gulf's reliability constraints.

Q. What are some of those additional factors that you mentioned?

A. As I just explained, 12 MCP & 1/13th energy best reflects Gulf's reliability constraints. It also accounts for Gulf's objective of striving to minimize overall cost of production.

Q. Please continue.

A. Because Gulf must be able to serve load in every hour of the year and strive to do so at the least cost, Gulf, like most utilities, builds base load plants in addition to peakers. While peakers are built basically for serving reliability needs, base load plants have a dual purpose of serving reliability needs as well as minimizing operational costs throughout the year. These base units are considerably more expensive than peakers, and their costs go into the overall production function as do peakers. Therefore, it is logical to allocate production costs throughout the year, which the 12 MCP and 1/13th energy does. The 4 CP or 4 CP/1 CP would spread these costs to a much more limited number of months and hours. It is conceivable that an allocator with as few as 4 or 5 CPs might enable some rate classes to escape any allocation of production costs at all, while a 12 MCP and 1/13th energy allocator will not do so.

Q. Has Gulf used the 12 MCP and 1/13th energy allocator for many filings?

A. It has been used since the late 1980's and obviously influenced present rates. We've found it to produce stable results over time. It has also aligned well with FERC's preferences.

Q. What production allocator does FERC favor?

A. In the past, FERC has used 12 MCP for both production and transmission in many cases. FERC has also recommended a test of peak loads to suggest whether to use 12 MCP or 4 MCP.

Q. Did you conduct this FERC test for Gulf?

A. Yes, and it resulted in a recommendation of 12 MCP.

Q. Is it your conclusion that 12 MCP and 1/13th energy is the most appropriate allocator for Gulf's production costs?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)
)
COUNTY OF COBB)

Docket No. 160186-EI

Before me the undersigned authority, personally appeared Michael T. O'Sheasy, who being first duly sworn, deposes, and says that he is a Vice President with Christensen Associates, Inc., and that the foregoing is true and correct to the best of his knowledge, information, and belief.

s/ Michael T. O'Sheasy
Michael T. O'Sheasy
Vice President

Sworn to and subscribed before me this 2nd day of February, 2017.

Diane E. Ware
Notary Public, State of Georgia at Large

Commission No. —

My Commission Expires 01/14/2020

Personally Known ______ OR Produced Identification ✓

Type of Identification
Produced Georgia Driver License

DIANE E. WARE
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January 14, 2020
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