BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY GULF POWER COMPANY	)	**DOCKET NO. 160186-EI**
IN RE: PETITION FOR APPROVAL OF 2016 DEPRECIATION AND DISMANTLEMENT STUDIES, APPROVAL OF PROPOSED DEPRECIATION RATES AND ANNUAL DISMANTLEMENT ACCRUALS AND PLANT SMITH UNITS 1 AND 2 REGULATORY ASSET AMORTIZATION, BY GULF POWER COMPANY	)	**DOCKET NO. 160170-EI**

Direct Testimony and Exhibits of

Amanda M. Alderson

On behalf of

Federal Executive Agencies

January 13, 2017

BRUBAKER & ASSOCIATES, INC.

Project 10353

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Table of Contents to the
Direct Testimony of Amanda M. Alderson

Page

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Direct Testimony of Amanda M. Alderson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Amanda M. Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of Federal Executive Agencies ("FEA"). FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Gulf Power Company ("Gulf Power" or "Company") and purchase electric utility service from Gulf Power.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A I will address the filed retail cost of service studies ("COSS") of Gulf Power, and the resulting spread of the required revenue increase.

My silence in regard to any issue should not be construed as an endorsement of Gulf Power's position.

I. Summary of Findings and Recommendations

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE 2015 TEST YEAR COSS.

A. My cost of service findings and recommendations are summarized as follows:

1. I find the Company's proposed production cost of service method to be inappropriate. Inclusion of an energy component in the allocation of fixed production costs does not align with cost incurrence, and the Florida Public Service Commission ("Commission") practice using the 12 coincident peak ("CP") demand and 1/13th energy allocation method does not align with the current common methods used elsewhere in the industry.
2. Gulf Power's production planning processes, in coordination with the other electric utility subsidiaries in the Southern Company System, and its reserve margin calculations are based on peak demand in the system peak months. Any

fuel or energy related cost savings taken into account during production planning, and other considerations such as loss of load probability, are used in the development of the Southern Company System target reserve margin, but ultimately the reserve margin itself is calculated on a system peak basis. Further, Gulf Power rightfully allocates all variable production costs using an energy allocation of fuel costs and operation and maintenance ("O&M") costs. Therefore, Gulf Power's fixed production costs should be allocated on a 100% demand component method.

3. I recommend the production cost allocator used to develop the COSS in this proceeding be a 100% demand method, using either the 4 summer CP or 4 summer / 1 winter CP method. The Gulf Power system and Southern Company System load characteristics support both of these 100% demand allocators.

4. I find the underlying data used by Gulf Power to develop the retail class production cost allocators to be inconsistent with the 2015 Cost of Service Load Research Study filed by Gulf Power on June 9, 2016. For numerous rate classes, the ratio between the test year data and load research data annual consumption (energy) is considerably different from the ratio between the test year and research data monthly demand average (12 CP). The Florida Commission requirements of Minimum Filing Requirement ("MFR") E-11 instruct Gulf Power to provide justification and workpapers for its estimation methodology for test year coincident and noncoincident demands, and only scant justification is provided. These unexplained inconsistencies call into question the accuracy of the developed cost allocation factors.

5. Because of the lack of supportable data available, I recommend that the spread of the revenue increase across customer classes be adjusted to fall within a more narrow range around the system average increase. When the COSS results are considered unreliable, it is more reasonable to increase the rates for each class on a more equal basis, and in this instance I recommend no class receive greater than a 1.1x the system average increase.

II. Gulf Power's Proposed COSS

Q HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE FILING IN THIS PROCEEDING?

A Yes. I have reviewed the testimony of Gulf Power witness Mr. Michael O'Sheasy and the COSS he has presented therein. The Company has filed two versions of its COSS for the 2015 Test Year. The first version uses similar cost of service allocation methods to those the Company filed in its 2014 test year case. The second version is required by MFRs in Florida, and is the same as the first COSS except that it eliminates the use of the Minimum Distribution Study in allocation of certain distribution costs. The Company proposes designing customer rates based off the first COSS version, incorporating the Minimum Distribution Study into cost allocation.

Q PLEASE COMMENT ON THE COMPANY'S PROPOSED CONTINUED USE OF THE MINIMUM DISTRIBUTION STUDY.

A I agree with and support the Company's proposed continued use of recognizing the customer-related component in cost causation for certain distribution Federal Energy Regulatory Commission ("FERC") account asset costs through use of a Minimum

Distribution Study. I agree with Mr. O'Sheasy's excellent in-depth explanation of the necessity of using a Minimum Distribution Study. The Commission has previously approved Gulf Power's use of the Minimum Distribution Study in its 2012 test year case, and all of the other Southern Company System utilities use the Minimum Distribution Study to allocate distribution costs.[1] The study is similarly used in many other jurisdictions across the country. I recommend that the Commission approve Gulf Power's continued use of the Minimum Distribution Study in setting rates in the instant proceeding.

III. Production Cost Allocation

Q PLEASE DESCRIBE THE PRODUCTION COST ALLOCATION METHOD GULF POWER IS PROPOSING IN THIS CASE.

A Gulf Power and Florida investor-owned utilities ("IOU") generally, have historically relied upon the 12 CP and 1/13th method to allocate fixed production plant costs. This method classifies 1/13th of the fixed production costs as energy-related, and allocates those costs on energy requirements. The remaining 12/13^{ths} are classified as demand-related and allocated to classes based on the average of the classes' 12 coincident peaks. Gulf Power is not proposing a change to this method.

I am not aware of any other jurisdiction currently using the 12 CP and 1/13th method. The more common energy-weighting method is the Average and Excess Demand ("AED") method, employed in, for example, Arizona, Colorado, Missouri, New Mexico, Texas, etc.

[1] Direct Testimony of Michael T. O'Sheasy, page 27, lines 1-14.

Q WHAT ARE YOUR CONCERNS WITH THE COMPANY'S PROPOSAL TO CONTINUE USING THIS ALLOCATION METHOD?

A Using an energy component in the allocation of fixed production costs is illogical and not tied to cost incurrence. Gulf Power plans its production system to meet its anticipated peak loads and must hold enough generation capacity to meet a 14.75% reserve margin calculated on a summer peak and winter peak demand basis.[2]

Gulf Power plans for production capacity increases considering the system coincident peak demands, and the coincident peak demands of the Southern Company System as a whole.[3] The Company has described its production planning processes and the derivation of its reserve margin metrics in testimony and data responses in this proceeding,[4] and the underlying determinative factor for whether additional capacity is necessary is whether the existing generation fleet can meet Gulf Power's summer and winter coincident peak demands. Consideration for operating characteristics in all hours of the year, or scheduled maintenance occurring during off-peak periods, is reflected in the energy allocation of the variable costs for these production assets, and in the derivation of the target reserve margin. But the reserve margin itself, and the determination of whether Gulf Power has sufficient production capacity, is determined based on system coincident peak demand.

Therefore, Gulf Power's fixed production costs should be allocated on a 100% demand allocation method, and Gulf Power's variable production costs should continue to be allocated on a variable energy method.

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[2]Gulf Power's responses to FEA POD Nos. 22 and 25, discussed in further detail hereafter.
[3]Direct Testimony of Michael T. O'Sheasy, page 13, lines 15-18.
[4]I will elaborate on Gulf Power's production planning process in the next section of this testimony.

Q WHAT IS YOUR RECOMMENDATION CONCERNING ALLOCATION OF FIXED PRODUCTION COSTS?

A I recommend that a 100% demand allocation factor be used in allocating costs in the Company's COSS model in the instant proceeding. The demand factor to be used should be either a 4 summer CP or 4 summer / 1 winter CP allocation factor based on the load characteristics of the Gulf Power and Southern Company Systems.

IV. Production System Planning

Q HOW DOES GULF POWER'S PRODUCTION PLANNING IMPACT PRODUCTION COST ALLOCATION?

A A fundamental tenet of proper cost of service allocation is to align the allocation of costs with the way in which those costs are incurred by the utility. For production costs specifically, a utility must design the total amount of production capacity it holds in such a way that that capacity can meet the peak system demand of all customers. Therefore, allocating fixed production costs on an allocation method that is based on customers' contributions to the system peak demand would align cost allocation with cost incurrence.

Q HOW DOES THE COMPANY PLAN FOR ITS PRODUCTION CAPACITY ADDITIONS?

A Witness Jeffrey A. Burleson explained in his direct testimony that Gulf Power coordinates its production planning processes with the Southern Company System and the other member electric utilities:

> As a part of the coordinated planning process, each retail operating company develops its own load forecast and demand side plan. The load forecasts and demand side plans of the operating companies are aggregated and an optimal mix of new capacity additions is identified

> to meet the aggregate load of the retail operating companies. The capacity need for each future year is allocated to each operating company that is projected to have a capacity need in a given year. **The allocation of the capacity need is proportional to the amount of capacity needed to move each of the operating companies that have a capacity need in a given year to the target planning reserve margin based on each operating company's own load and existing resources.**[5]

Witness O'Sheasy writes, as well, of the 12 CP allocation method, it "recognizes the fact that Gulf's system is planned and operated for the purpose of meeting these [coincident peak] demands."[6]

Q WHAT IS A RESERVE MARGIN?

A A utility's reserve margin is the excess production capacity above expected system demand at the hours of the annual peaks of the system. A planning reserve margin target is used by system planners to ensure that the generating capacity is available when demands on the system are at the highest levels taking into account forecasting error and weather fluctuations, in order to greatly reduce the likelihood of brownouts or blackouts. Gulf Power's target reserve margin is 14.75%.[7]

Q HOW DOES GULF POWER CALCULATE ITS PRODUCTION CAPACITY AMOUNT IN ORDER TO MEET ITS TARGET RESERVE MARGIN?

A Gulf Power calculates its reserve margin on a single summer coincident peak and single winter coincident peak basis. Gulf Power annually files a Ten Year Site Plan ("TYSP") and coordinates its resource planning with the Southern Company System through its Integrated Resource Planning ("IRP") process. Gulf Power's 2016 TYSP was provided in response to FEA POD No. 22, and shows that Gulf Power tests its

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[5]Direct Testimony of Jeffrey A. Burleson at pages 6-7, emphasis added.
[6]Direct Testimony of Michael T. O'Sheasy, page 13, lines 16-17.
[7]Gulf Power's response to FEA POD No. 25.

reserve margin requirements on both its projected one summer and one winter peaks.[8]

FEA requested a copy of the most recent Southern Company System IRP, but was provided only a summary of the IRP planned resource additions, and estimated annual reserve margins for the forecast period. This summary, found in Gulf Power's response to FEA POD No. 21, lists the reserve margin values at the time of the annual summer peak only, not showing the winter peak. The Southern Company System typically peaks in the summer.

Q ARE OTHER PLANNING ELEMENTS BESIDES PEAK SYSTEM DEMAND CONSIDERED IN THE PRODUCTION PLANNING PROCESS?

A Yes. The overall cost of additional production assets as well as the anticipated reliability of various asset types is considered. These metrics are an input to the derivation of the Southern Company System target reserve margin. Gulf Power's response to FEA POD No. 26 says:

> The analyses to identify the minimum long-term planning reserve margin considers [sic] uncertainties associated with unforeseen unit outages, abnormal weather, load forecast deviations, and market availability risk. . . . **The objective of this study is to find the target reserve margin where the sum of these costs (i.e., those related to reliability and those related to carrying reserves) is minimized** (i.e., the minimum cost point), adjusted to balance costs and acceptable levels of reliability risks. [emphasis added]

In other words, the development of the target reserve margin is done in an effort to minimize the probability that system production capacity will be insufficient to meet expected peak load, while also keeping the total cost of holding excess capacity reserves at a reasonable level. This exercise contemplates various factors

[8] "Gulf [will] meet its reserve margin requirements until June 2023 of the 2016 TYSP cycle," page 3 of the 2016 TYSP Executive Summary. Schedules 7.1 and 7.2 of the 2016 TYSP show reserve margin falling below the 14.75% target in 2024, calculated on the one summer and one winter system peaks.

such as weather patterns, predicted unit outages of various capacity types, market commodity costs and variability, and possible customer load forecast deviations. But these considerations are used to determine the target reserve requirement which ultimately is a formula calculated solely on the system's summer and winter peak demands.

V. Gulf Power's System Load Characteristics

Q PLEASE DESCRIBE THE GULF POWER SYSTEM LOAD CHARACTERISTICS.

A Gulf Power is generally a summer peaking utility, which is typical of utilities in the South with significant air conditioning load. A look at the historical system peaks shows that January recently has also exhibited very high demands. My Exhibit AMA-1 shows that in 2015, July was the maximum peak, but January was within 99.9% of the July peak. January was the single system peak in 2014, during the national Polar Vortex event. Exhibit AMA-1 shows the Gulf Power annual peaks over the past four years, and over the projected period from 2016 through 2017. The projected system peaks were provided by Gulf Power in its MFRs and corroborate the fact that Gulf Power expects its system to continue exhibiting a summer-only peak pattern.

Q PLEASE DESCRIBE THE SOUTHERN COMPANY SYSTEM LOAD CHARACTERISTICS.

A The Southern Company System as a whole exhibits a similar summer-peaking pattern, with the January max demands in 2010, 2014, and 2015 nearly meeting or exceeding the summer peak. Exhibit AMA-2 shows the historical Southern Company monthly peaks for 2010 through 2015. Because Gulf Power plans its production system in coordination with Southern Company, the Southern Company System characteristics should influence the determination of proper cost allocation.

Q HOW SHOULD THESE SYSTEM LOAD CHARACTERISTICS GUIDE COST ALLOCATION DECISIONS?

A Reviewing the system peaks for both Gulf Power and Southern Company allows us to understand how the utility must determine whether and how much additional production capacity is needed to serve firm load. Because four summer months of June through September, and occasionally, January, generally fall within 90% of the single system peak, Gulf Power and Southern Company must plan to meet the peaks in each of these months as they each have a high probability of exhibiting the actual peak system demand in a given year. Therefore, the demand component of the production cost allocator should be based on classes' contributions to either the 4 summer or 4 summer / 1 winter CPs.

VI. Alternative Production Cost Allocation Method

Q HAVE YOU MADE CHANGES TO THE COMPANY'S COSS TO REFLECT YOUR ALTERNATIVE PRODUCTION COST ALLOCATION METHOD RECOMMENDATION?

A Yes. My Exhibit AMA-3 provides the results of a COSS using the 4 summer CP / 1 winter CP retail cost allocation method.

Q DO YOU RECOMMEND THE COMMISSION ACCEPT THESE RESULTS IN THIS CASE?

A No. The class coincident peak data provided by Gulf Power are not reliable. Gulf Power witness Lee P. Evans claims that the 2015 Cost of Service Load Research Study, filed with the Commission on June 9, 2016, was the data used to develop the 12 CP, NCP, and energy allocation factors in the Company's COSS.[9] MFR Schedule E-11 provides the Load Research Study 12 CP, NCP, and energy for each class, and the corresponding values used in the COSS allocators. Gulf Power accounts for known and measurable changes between the 2015 Load Research data and the COSS test year, such as rate migrations for large industrial customers and known changes in loads,[10] but one would assume these load changes would similarly impact energy and demand levels, unless specifically known otherwise. A review of the data shows considerable differences between the energy and demand ratios for many classes. My Exhibit AMA-4 provides this data.

Q PLEASE DESCRIBE YOUR CONCERN WITH THE GULF POWER MFR SCHEDULE E-11 DATA.

A My Exhibit AMA-4 shows the 2015 Load Research data and the COSS Test Year data derived from the Load Research data. Gulf Power did not provide any workpapers supporting the formula by which it developed its COSS Test Year data. I have calculated the ratio difference between the Load Research data and COSS Test Year data for each metric, energy, 12 CP demand, and NCP demand, in columns C, F, and I on Exhibit AMA-4. I have highlighted a number of rate classes that show unexplained differences between the ratios for energy and demand. For

[9] Direct Testimony of Lee P. Evans, page 16, lines 18-23.
[10] MFR Schedule E-11, page 1.

example, the Large Power ("LP") class had a 2015 Load Research annual energy amount of 327,193 MWh, and Gulf Power adjusted that value up by 6% to 345,232 MWh for the COSS Test Year. But Gulf Power adjusted upward by 12% the Rate LP 2015 Load Research 12 CP demand value to determine the COSS Test Year 12 CP demand value used in the development of the 12 CP allocation factor. Other classes with unexplained discrepancies include Rates RSVP[11] and RTP. One would expect load growth to generally affect customer energy and demand levels roughly similarly, unless specific assumptions for a given customer dictate otherwise.

Q COULD CUSTOMER-SPECIFIC LOAD GROWTH INFORMATION EXPLAIN SOME OF THE DISCREPANCIES IN RATIOS SHOWN ON EXHIBIT AMA-4?

A Yes. Especially for the Standby ("SBS") Rate and Contract ("CSA") Rate customers, these customers may very well intend to increase their annual energy consumption targeted only to the non-peak times, and therefore their estimated peak demands would not change in the same way total energy levels would change.

But Gulf Power has provided no such support for either the large user load changes nor the Test Year energy, 12 CP, and NCP values for the smaller use customers.

Q WHAT OBLIGATION DOES GULF POWER HAVE TO PROVIDE SUPPORT FOR ITS TEST YEAR ALLOCATOR VALUES?

A MFR E-11 requirements are as follows, that Gulf Power must provide: (1) a description of how coincident and noncoincident demands were developed; (2) the

[11]Although Rate RSVP is meant to be a critical pricing rate, incentivizing residential customers to reduce their peak demands, Gulf Power's 2015 tariffs, and proposed RSVP rates in this case, provide no such incentive because the energy tariff prices are the same no matter the time of day or season. Therefore, one would assume any load growth in the RSVP class would affect annual energy and peak demand similarly.

workpapers for the actual calculations; and (3) justification for the methodology used to derive projected demands if that methodology was not the application of ratios of classes' coincident and noncoincident load to actual MWh sales. Page 1 of MFR Schedule E-11 provides insufficient explanation and justification. Workpapers showing actual calculations, rather than just input final values, were not made available for review.

Q DO YOU ANTICIPATE THAT A SWITCH TO A PRODUCTION ALLOCATION METHOD BASED 100% ON 4 SUMMER CP / 1 WINTER CP DEMAND WOULD BE A MEANINGFUL COST SHIFT BETWEEN CUSTOMER CLASSES?

A Yes. Table 1 below provides a comparison of the various production cost allocation factors I have discussed in this testimony. A movement from the Company's proposed 12 CP and 1/13th method to a 100% demand 4 summer CP / 1 winter CP allocation factor is meaningful for a number of classes. I estimate that a shift in the allocation factor for any one class of only half of a percentage point would result in an approximate $4 million shift in total revenue requirement to the class.[12] For nearly all of the rate classes besides the Residential class, a shift in $4 million in revenue requirement is nearly all, or fully all, of the proposed class revenue increase in this proceeding.

[12] Based on a comparison of the results between my and the Company's COSS.

TABLE 1

Comparison of Allocation Factors
Across Various Production Allocation Methods

Rate Class	Company Proposed 12 CP & 1/13th[1]	Average & Excess[2]	4 Summer CP[2]	4 Sum. CP / 1 Winter CP[3]
Residential	55.52%	55.82%	53.78%	56.24%
GS	2.77%	2.88%	3.06%	2.90%
GSD/GSDT	21.87%	21.73%	23.05%	21.84%
LP/LPT	6.71%	6.49%	6.87%	6.51%
Major Accounts	12.62%	12.15%	12.93%	12.19%
OS	0.50%	0.92%	0.31%	0.32%
Total Retail	100.00%	100.00%	100.00%	100.00%

Sources:
1. MFR Schedule E-9
2. AMA Workpaper 1
3. Exhibit AMA-3

Q WHAT IS YOUR PROPOSED PRODUCTION COST ALLOCATION METHOD?

A I recommend that the Company provide the results in this instant proceeding in its rebuttal testimony of a 100% demand 4 summer CP / 1 winter CP production cost allocation method using fully justified input allocation data. I believe that this allocation method is most supported by the Company's system resource planning and the load characteristics and the nature of the Gulf Power and Southern Company summer peaking system.

In the absence of the reliable COSS results, I recommend that the final approved spread of the revenue increase across classes be adjusted to fall within a more narrow band around the system average increase. Because the data necessary to verify the reasonableness of the Company's estimated class coincident peaks has not been made available to the Commission, and movement to a more reasonable production cost allocation method would meaningfully affect the COSS results, one cannot rely on the Company's filed COSS results to determine the appropriate spread of the revenue across rate classes.

VII. Spread of Revenue Increase

Q WHAT IS YOUR PROPOSAL CONCERNING THE SPREAD OF THE APPROVED REVENUE INCREASE?

A I propose that the spread be narrowed across classes, closer to the system average increase. Specifically, I propose that no class receive more than 1.1x the system average increase. This is a reduction to the Company's proposed limit of 1.5x the system average increase.[13] Because the underlying class energy and demand data used for many of the allocation factors in the Company's COSS are unreliable based on the data available, I recommend that the 1.5x the system average band be reduced to 1.1x the system average so as to spread the approved revenue increase more evenly across customer classes.

Q PLEASE DESCRIBE HOW YOU DEVELOPED YOUR PROPOSED REVENUE SPREAD.

A Still using the Company's and my adjusted COSS results as a guide, for those classes that are in need of a considerably higher than system average increase, I recommend an increase at 1.1x the system average. For the classes deserving of a lower than system average increase, I have recommended a 0.9x the system average increase. For those classes which require nearer a system average

[13]Direct Testimony of Lee P. Evans, page 6, line 16.

increase according to the Company and my proposed COSS results, I have proposed an increase approximately equal to the system average increase.

Table 2 below provides a comparison of my proposed spread of the increase to the Company's proposal.

TABLE 2

Comparison of Company and FEA Proposed Revenue Increase
Dollars in Thousands

Rate Class	Present Base Revenues	Company Proposed Increase[1] ($000)	Percent	Index	FEA Proposed Increase[2] ($000)	Percent	Index
Residential	$ 335,138	$ 60,921	18.2%	0.9	$ 65,144	19.4%	1.0
GS	22,687	4,663	20.6%	1.1	4,973	21.9%	1.1
GSD/GSDT	111,016	20,649	18.6%	1.0	19,212	17.3%	0.9
LP/LPT	28,475	6,091	21.4%	1.1	5,475	19.2%	1.0
Major Accounts	39,815	11,472	28.8%	1.5	8,728	21.9%	1.1
OS	18,188	2,885	15.9%	0.8	3,148	17.3%	0.9
Total Retail	$ 555,319	$ 106,681	19.2%	1.0	$ 106,681	19.2%	1.0

Sources:
1. MFR Schedule E-13a
2. Exhibit AMA-3

*Note: Excludes Fuel and Other Revenue (fees, rental payments, etc.)

Q WHY IS YOUR PROPOSED NARROWING OF THE SPREAD OF THE REVENUE INCREASE TO CLASSES MORE REASONABLE THAN THE COMPANY'S PROPOSAL?

A The Company's proposed band, shown clearly in Table 2 above, ranges from 0.8x to 1.5x the system average increase. My proposed narrowing of the band, using 0.9x to 1.1x, does not impact the total revenue collected by the Company, but rather apportions the revenue increase in a more even-handed manner. Because the energy and demand data underlying many of the COSS allocation factors have not been sufficiently supported as reasonable estimates, customers should not receive undo rate increases based primarily on potentially flawed COSS results. For these reasons, I recommend narrowing the band and spreading the increase more evenly, an example of which is shown in Table 2 above.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Amanda M. Alderson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Amanda Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from the University of Illinois at Urbana-Champaign in 2008 where I received my Bachelor of Arts in Economics, with minor studies in Statistics and International Business. I earned my Masters of Business Administration Degree with a concentration in Logistics and Operations Management upon graduation from the University of Missouri-St. Louis in 2011.

I joined BAI in 2008 as an analyst. Then, in September 2011, I joined the consulting team of BAI.

I have worked on various issues including embedded and marginal cost of service studies, rate design, power procurement and portfolio management, contract negotiation and environmental and sustainability compliance management.

In the regulated arena, I have evaluated cost of service studies and rate designs proffered by other parties in cases for various utilities, including in New York, Indiana, Missouri, Oregon, Quebec, Nova Scotia, and others. I have conducted bill audits, rate forecasts and tariff rate optimization studies. I have performed utility investment prudence reviews with respect to such items as fuel, purchased power and renewable energy investments.

I have also provided support to clients with facilities in deregulated markets, including drafting supply requests for proposals, evaluating supply bids, and auditing competitive supply bills. I have also prepared and presented to clients reports that monitor the electric market and recommend strategic hedging transactions.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

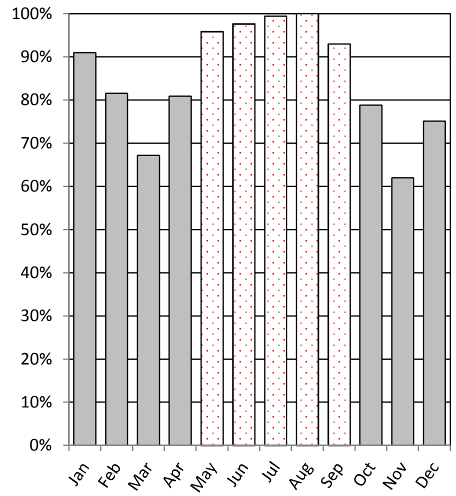
In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

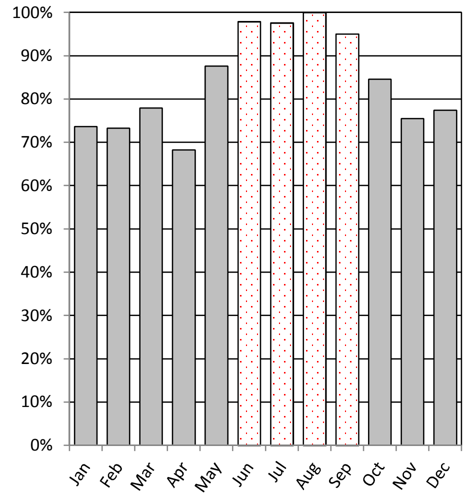
Gulf Power Company
Docket No. 160186-EI & 160170-EI

Analysis of Gulf Power's Monthly Peak Demands
as a Percent of the Annual System Peak

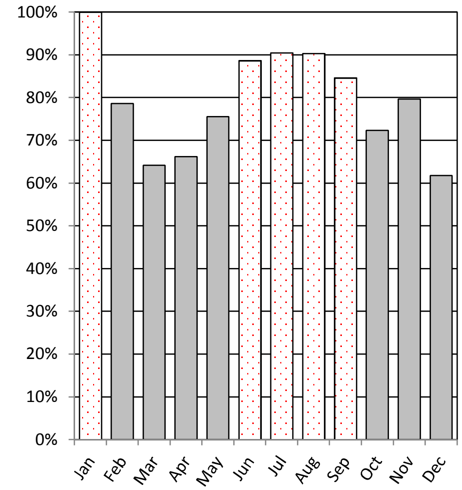
Calendar Year 2012



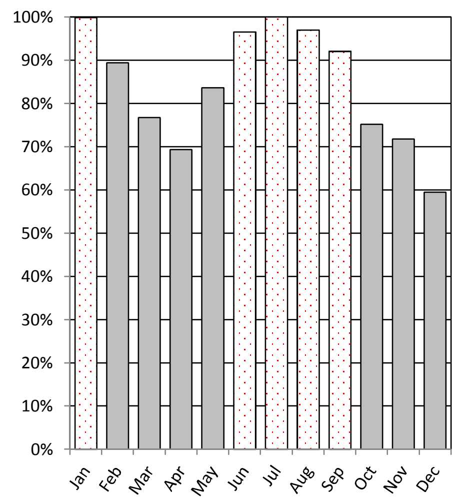
Calendar Year 2013



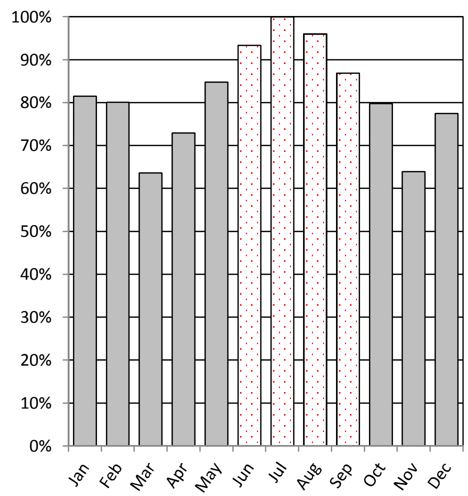
Calendar Year 2014



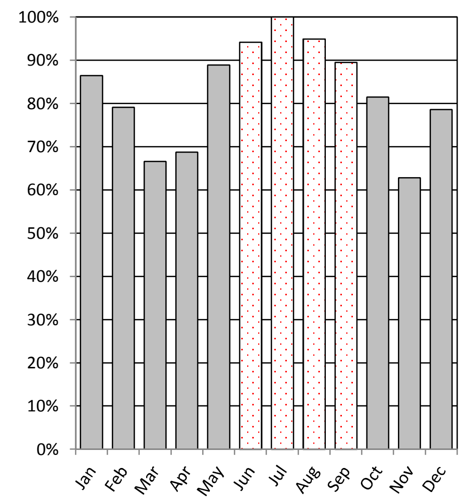
Calendar Year 2015



Calendar Year 2016
(Actual through August 2016)



Calendar Year 2017
(Projected)

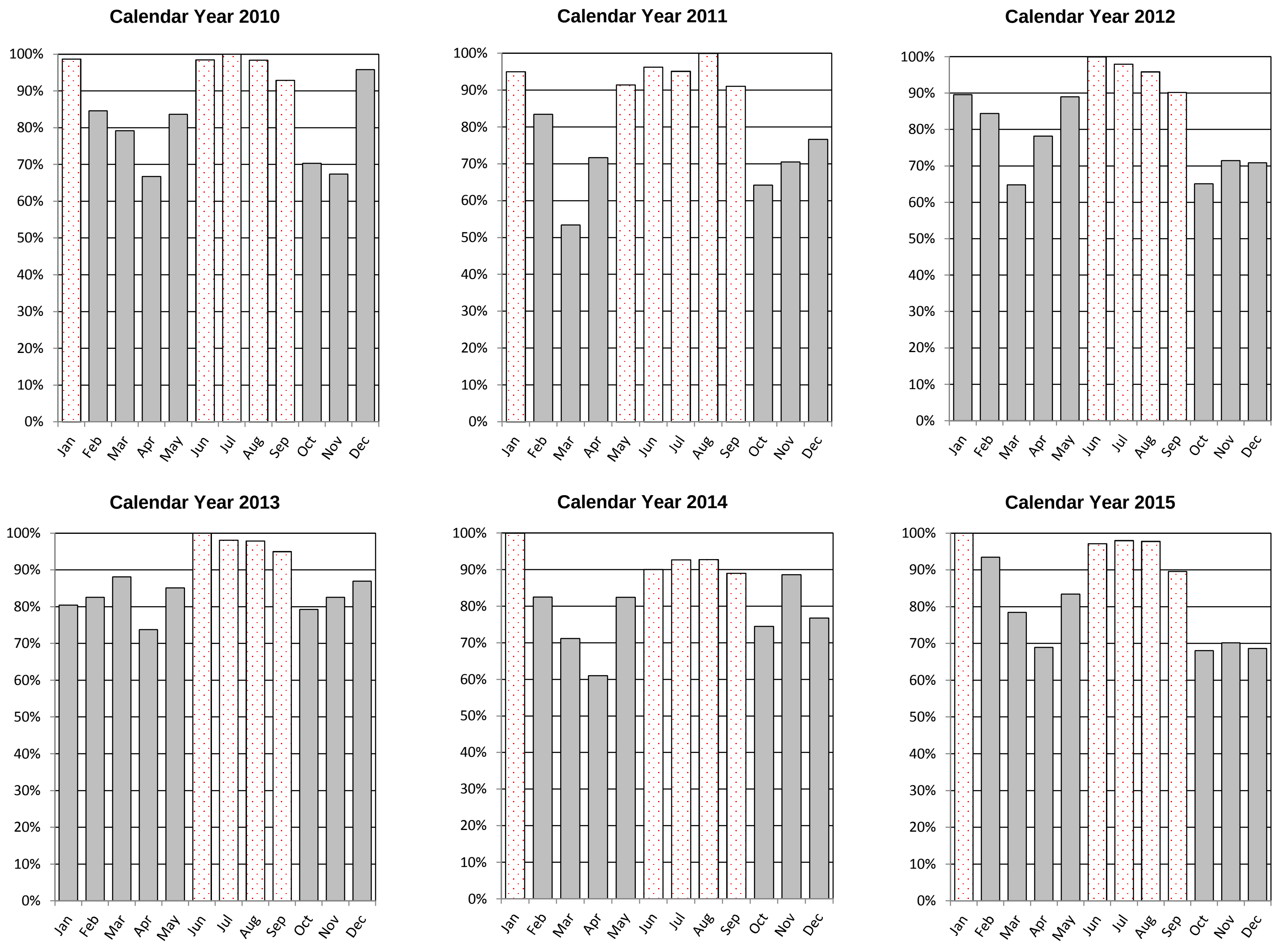


Source: MFR Schedule E-18

Gulf Power Company

Docket No. 160186-EI & 160170-EI

Analysis of Southern Company's Monthly Peak Demands
as a Percent of the Annual System Peak



Source: Southern Company FERC Form 714

Gulf Power Company
Docket No. 160186-EI & 160170-EI

Alternative COSS Results
100% Production Demand 4 Summer CP / 1 Winter CP - With MDS

Line	Description	Total Retail Service (A)	Total Residential (B)	Rate GS (C)	Rate GSD/GSDT (D)	Rate LP/LPT (E)	Major Accounts (F)	Rate OS (G)
1	Revenue Requirement - Equal System ROR - Proposed Rates	$ 703,455	$ 421,215	$28,991	$ 133,405	$37,286	$ 67,102	$15,456
2	Present Revenue Requirements	596,672	358,478	23,823	118,132	31,902	45,709	18,628
3	Revenue Excess / Deficiency	106,783	62,737	5,168	15,273	5,383	21,394	(3,172)
4	Revenue Req. Index - Equal System ROR - Prop. Rates	84.82%	85.11%	82.17%	88.55%	85.56%	68.12%	120.52%

Gulf Power Company
Docket No. 160186-EI & 160170-EI

Comparison of Energy, 12 CP Demand, and NCP Demand Allocator Values
Gathered in Gulf Power Load Research Study vs. Developed for COSS Test Year

		Energy (kWh)			12 CP Demand (kW)			NCP Demand (kW)		
Line	Rate Class	2015 Load Research (A)	2015 COSS Test Year (B)	Incr/ (Decr) (C)	2015 Load Research (D)	2015 COSS Test Year (E)	Incr/ (Decr) (F)	2015 Load Research (G)	2015 COSS Test Year (H)	Incr/ (Decr) (I)
1	RS	5,106,032,120	5,020,330,872	-2%	1,014,442	987,058	-3%	1,431,968	1,424,861	0%
2	RSVP	257,479,211	316,560,673	23%	45,601	44,606	-2%	77,268	76,884	0%
3	GS	290,197,048	292,139,007	1%	52,350	51,277	-2%	73,656	74,149	1%
4	GSD	2,616,190,991	2,650,042,274	1%	406,606	401,393	-1%	525,924	532,728	1%
5	LP	327,193,229	345,231,717	6%	47,426	53,138	12%	58,775	66,194	13%
6	LPT	544,201,581	542,497,012	0%	72,737	71,745	-1%	87,907	65,291	-26%
7	RTP	1,673,697,239	1,643,584,389	-2%	223,291	233,741	5%	177,594	174,974	-1%
8	SBS	5,435,914	11,903,272	119%	140	139	-1%	65,183	-	-100%
9	CSA	127,593,845	49,000,000	-62%	18,146	5,353	-71%	15,131	6,518	-57%
10	OS	156,272,577	151,235,697	-3%	8,294	8,282	0%	30,829	31,789	3%

Source: Gulf Power MFR Schedule E-11

CERTIFICATE OF SERVICE
Docket Nos. 16-0170-EI, 16-0186-EI

I **HEREBY CERTIFY** that a true and correct copy of the foregoing Direct Testimony of Michael P. Gorman, Amanda M. Alderson, and Brian C. Andrews has been furnished by electronic mail this 13th day of January, 2017 to the following:

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