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**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

**In Re: Petition for Increase in
Rates by Gulf Power Company**) **Docket No. 110138-EI**

Direct Testimony of David L. Stowe

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A David L. Stowe. 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 my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies
("FEA").

1 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 A The purpose of my testimony is to describe my review of Gulf Power's embedded
3 cost of service ("ECOS") study, and to address certain of Gulf Power's allocation
4 methods.

5

6 **Company ECOS Discussion**

7 **Q HAVE YOU REVIEWED THE ECOS STUDY PROVIDED BY GULF POWER?**

8 A Yes.

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10 **Q PLEASE DESCRIBE WHAT YOU DETERMINED FROM YOUR REVIEW.**

11 A The ECOS study presented in Gulf Power's direct testimony is similar to the
12 ECOS study that was approved by the Florida Public Service Commission
13 ("Commission") in Gulf Power's 2002 case (Docket No. 010949-EI). Specifically,
14 Gulf Power's ECOS uses the 12 MCP & 1/13th kWh allocation for generation
15 costs, a 12 MCP allocation of transmission costs and non-coincident peak
16 ("NCP") demand allocation factors for primary and secondary distribution costs.

17 Gulf Power's ECOS study also recognizes the concept of the minimum
18 distribution system ("MDS") and relies on the zero intercept ("ZI") method to
19 classify customer-related distribution costs in Federal Energy Regulatory
20 Commission ("FERC") Accounts 364-368. I support Gulf Power's recognition of
21 the MDS concept, and also support its use of the ZI method to estimate the
22 percentage of costs that should be allocated based on the number of customers.
23 Gulf Power's use of the ZI could be improved, but nevertheless provides a
24 reasonable estimate of the customer-related portion of distribution costs.

25

1 Q DOES GULF POWER ATTEMPT TO FOLLOW GENERALLY ACCEPTED
2 COST OF SERVICE PRACTICES?

3 A Yes. Gulf Power witness Mr. O'Sheasy correctly states:

4 "The overall objective of a cost-of-service study is to assign or
5 allocate costs fairly and equitably to all customers. This objective
6 is accomplished when the resulting cost-of-service study reflects
7 "cost causation," i.e., those customers who caused a particular
8 cost to be incurred by the Company in providing them service
9 should be responsible for that cost... Joint or common costs must
10 be allocated to customer groups based on the nature (i.e., drivers)
11 of the costs incurred, and the aggregate requirements and service
12 characteristics of the customers that caused the costs to be
13 incurred. By adhering to this fundamental and essential principle
14 of cost causation, the results of the cost-of-service study will be
15 fair and equitable to all customers." (Direct Testimony of M. T.
16 O'Sheasy, page 6, lines 3-8 and 16-21).

17 This portion of Mr. O'Sheasy's testimony indicates Gulf Power's
18 commitment to identifying the cost-causative factors that influence the
19 Company's investments, and its desire to allocate its costs in a manner that
20 appropriately reflects these causative factors.

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1 Q HOW DO THE COST OF SERVICE METHODS PRESENTED IN GULF
2 POWER'S DIRECT TESTIMONY COMPARE TO THE METHODOLOGY
3 APPROVED BY THE COMMISSION IN ITS LAST RATE CASE?

4 A The cost of service methods Gulf Power uses in this case differ from those
5 approved by the Commission in Gulf Power's last rate case only to the extent
6 that Gulf Power is again proposing the use of the MDS to identify and allocate
7 customer-related distribution system costs. To a large degree, Gulf Power's
8 presentation of its ECOS study is in accordance with its stated commitment to
9 cost causation. Nevertheless, there is one instance where Gulf Power has used
10 a particular allocation method simply because this method was approved in past
11 cases, even though Gulf Power witness O'Sheasy believes a better method
12 exists.

13

14 **Gulf Power's Use of 12 MCP & 1/13th kWh Allocation**

15 Q TO WHICH PARTICULAR ALLOCATION METHOD DO YOU REFER?

16 A I refer to the 12 MCP & 1/13th kWh allocation of generation costs. In his direct
17 testimony, Mr. O'Sheasy states:

18 "Although the Company does not agree that the use of 12-MCP &
19 1/13 kWh is a better allocator of generation level costs than a pure
20 12-MCP allocator would be, Gulf nevertheless prepared its study
21 in this case using the Commission-approved methodology. Gulf
22 continues to believe that a pure 12 MCP factor for generation
23 results in a more accurate cost allocation. However, using the
24 Commission's preferred method does not result in major variances
25 in cost allocation from the pure 12-MCP approach and does not

1 significantly impair Gulf in designing efficient rates.” (Direct
2 Testimony of M. T. O’Sheasy, page 16, lines 11-18).

3

4 **Q DO YOU AGREE WITH MR. O’SHEASY THAT THE COMMISSION’S**
5 **APPROVED 12 MCP & 1/13th KWH METHOD IS NOT THE BEST ALLOCATOR**
6 **OF GENERATION LEVEL COSTS?**

7 **A** Yes. The 12 MCP & 1/13th kWh allocator does not reflect cost-causative factors
8 that exist during Gulf Power’s peak load periods, but instead reflect a system
9 load that is far below the Company’s actual peak load. As such, this method
10 over-allocates generation costs to customer classes that use an above average
11 proportion of their electricity during off-peak periods, and therefore bear less
12 responsibility for the peak demand. Simultaneously, the 12 MCP & 1/13th
13 allocation understates the generation facility cost responsibility of customer
14 classes that contribute significantly to Gulf Power’s system peak, and therefore
15 bear greater responsibility for the Company’s investment in generation facilities.

16 I concur with Mr. O’Sheasy that the pure 12 MCP factor, when compared
17 to the 12 MCP & 1/13th kWh factor, results in a more accurate allocation of
18 generation costs.

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1 **Gulf Power's Use of MDS**

2 **Q DOES GULF POWER USE COST-OF-SERVICE METHODS TO IDENTIFY A**
3 **PORTION OF PRIMARY AND SECONDARY DISTRIBUTION COSTS AS**
4 **CUSTOMER-RELATED?**

5 **A** Yes. In its allocation of distribution system costs, Gulf Power uses the ZI
6 method¹ to estimate the amount of, and separately allocate, distribution system
7 costs that are incurred in proportion to the number of customers, from costs
8 incurred to serve the maximum load of those customers. Gulf Power's ECOS
9 study witness, Mr. O'Sheasy, states:

10 "The Minimum Distribution System (MDS) methodology is
11 necessary to accurately determine and allocate these customer-
12 related distribution costs. The misclassification of costs that
13 results from not using the MDS methodology sends misleading
14 price signals to customers. This misclassification also results in
15 different customer rate classes bearing more or less costs than
16 their cost-causative share of distribution costs. It is therefore
17 important to examine these customer-related costs and classify
18 them appropriately, which the MDS methodology enables us to
19 do." (Direct Testimony of M. T. O'Sheasy, page 16, line 24 –
20 page 17, line 7).

21

¹The two most widely recognized methods that are used to estimate the customer-related portion of costs are the ZI method, and the minimum system method. The National Association of Regulatory Utility Commissioners' 1992 publication of the Electric Utility Cost Allocation Manual ("NARUC Manual") includes both methods among those that are commonly used by utilities and approved by Commissioners. Throughout this testimony, I will use the term MDS in a broad sense to refer to the concept of the minimum distribution system in general, but will specify the ZI or minimum system when discussing a particular method that is used to estimate the cost of the MDS.

1 **The Commission's Past Acceptance of MDS**

2 **Q IS RECOGNITION OF MINIMUM COSTS A NEW COST OF SERVICE**
3 **CONCEPT?**

4 **A** No. Such costs are often recognized in the concept known as the MDS, which
5 represents a collection of costs that must be incurred to extend distribution
6 service to the customers. The MDS has been accepted as valid by numerous
7 state public utility commissions for decades. It has also been presented in the
8 NARUC Manual.²

9 The central idea behind the MDS concept is that there is a cost incurred
10 by a utility when it extends its primary and secondary distribution system, or
11 replaces a component on those systems, that is caused by the utility's obligation
12 to connect customers to its distribution system. This extension of the distribution
13 system is how the utility was built up over decades. By definition, the MDS
14 represents a portion of the cost of every distribution component necessary to
15 provide service, (i.e., meters, services, secondary and primary wires, poles,
16 substations, etc.) The cost included in the MDS, however, is only that portion of
17 the total distribution cost the utility must incur to provide service to customers; it
18 does not include costs specifically incurred to meet the peak demand
19 requirements of the customers.

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²See Chapter 6, Section II, pages 90-96 of the NARUC Manual.

1 Q HAS THE COMMISSION ADOPTED AN ECOS STUDY BY AN
2 INVESTOR-OWNED UTILITY ("IOU") THAT INCLUDED THE USE OF AN MDS
3 METHOD?

4 A No. In Order No. PSC-02-0787-FOF-EI, issued in Gulf Power's previous rate
5 case (Docket No. 010949-EI), the Commission stated:

6 "The Company and staff have proposed the use of a theoretical
7 minimum distribution cost as part of the customer cost While
8 we agree that sound regulatory practice should provide for a
9 customer charge to defray otherwise fixed costs, as proposed by
10 the Company and Staff, we do not agree that a theoretical cost of
11 a minimum distribution system is appropriate... The installation of
12 the distribution system is made in anticipation of a projected level
13 of actual use. The system does not contain a basic theoretical
14 minimum distribution system. Reliance on such a mechanism is
15 speculative at best. Instead, we believe the appropriate customer
16 charge should be based on the cost of the meter, service drop,
17 meter reading and basic customer service costs (not including
18 uncollectibles)." (Order No. PSC-02-0787-FOF-EI, issued June
19 10, 2002 in Docket No. 010949-EI, page 76, emphasis added).

20 Although it is widely agreed that distribution systems are installed in anticipation
21 of a projected level of peak load, this load is not the only cost-causative factor
22 affecting the cost of the distribution system. Safety and reliability standards, as
23 mandated in the Florida Administrative Code ("F.A.C."), also have a cost-
24 causative impact on the installation of Gulf Power's distribution system.
25 Furthermore, these cost-causative factors have a clearly identifiable "minimum"

1 requirement that is directly related to the number of customers on the system.

2 For example, F.A.C. Rule 25-6.034 – Standard of Construction, states:

3 "Each utility shall, at a minimum, comply with the National
4 Electrical Safety Code [ANSI C-2] [NESC], incorporated by
5 reference in Rule 25-6.0345, F.A.C.^[3]" (F.A.C. Rule 25-6.034,
6 subpart (2), emphasis added).

7 This rule, in and of itself, clearly shows that the requirements of the National
8 Electrical Safety Code ("NESC") serve as the basis of the smallest distribution
9 system that every Florida utility must construct.

10 However, other F.A.C. rules mandate that certain facilities be constructed
11 to NESC standards that are significantly higher than the minimum NESC
12 requirements. For example, F.A.C. Rule 25-6.0342 – Electric Infrastructure Storm
13 Hardening states:

14 "...This rule is intended to ensure the provision of safe, adequate,
15 and reliable electric transmission and distribution service for
16 operational as well as emergency purposes; *require the cost-*
17 *effective strengthening of critical electric infrastructure to increase*
18 *the ability of transmission and distribution facilities to withstand*
19 *extreme weather conditions*; and reduce restoration costs and
20 outage times to end-use customers associated with extreme

³F.A.C Rule 25-6.0345 – Safety Standards for Construction of New Transmission and Distribution Facilities states:

"(1) The Commission adopts and incorporates by reference the 2002 edition of the National Electrical Safety Code (ANSI C-2) [NESC], as the applicable safety standards for transmission and distribution facilities subject to the Commission's safety jurisdiction. For electrical facilities constructed on or after February 1, 2007, the 2007 NESC shall apply..."

1 weather conditions. This rule applies to all investor-owned electric
2 utilities." (F.A.C. Rule 25-6.0342, subpart (1), emphasis added).

3 This rule mandates that the storm hardening plans adopt the extreme wind
4 loading standards, specified in the 2007 version of the NESC, for new
5 construction, major planned expansions, rebuilds, or relocations of existing
6 facilities, and critical infrastructure facilities. Such F.A.C. rules cause Florida's
7 electric utilities to incur costs in a manner that is, in no way whatsoever, related
8 to the peak load of the customers, but is directly related to the existence of
9 customers on the system.

10

11 **Q DOES EMPIRICAL EVIDENCE EXIST THAT SUGGESTS THESE**
12 **DISTRIBUTION COSTS ARE CUSTOMER-RELATED AND SHOULD BE**
13 **ALLOCATED ON THE BASIS OF THE NUMBER OF CUSTOMERS?**

14 **A** Yes. In October 2002, the Department of Energy's National Renewable Energy
15 Laboratory ("NREL") published a Subcontractor Report entitled "State Electricity
16 Regulatory Policy and Distributed Resources: Distribution System Cost
17 Methodologies for Distributed Generation." This report, which describes the
18 research and findings of the Regulatory Assistance Project ("RAP"), analyzed the
19 embedded and marginal cost drivers for 124 U.S. utilities during the time period
20 1995-1999. With respect to the embedded cost drivers, which are most relevant
21 to the Gulf Power costs identified and analyzed in this case, the RAP very clearly
22 stated:

23 "What drives distribution plant investment? We reviewed the
24 relationship of investment in transformers and substations and
25 lines and feeders to system peak, system sales, number of

1 customers, and to overall system size. Using the 5-year average
2 investment, system peak, system sales, and number of customer
3 data, it becomes clear that the investment in transformers and
4 substations and in lines and feeders are highly correlated with
5 system peak and number of customers and somewhat less
6 correlated with system sales...

7 "The R^2 for transformers and substation plant investment
8 and system peak is 0.89, indicating a very strong correlation.
9 Similarly, lines and feeders and system peak also exhibit a strong
10 correlation with an R^2 of .89. Correlations of investment with the
11 customers show even higher R^2 values of 0.96 and 0.97, for
12 transformers and substations and lines and feeders, respectively.
13 When compared to system energy, the R^2 drops significantly to
14 only .49 and .42 for transformers and substations and for lines and
15 feeders, respectively." (NREL Subcontractor Report, State
16 Electricity Regulatory Policy and Distributed Resources:
17 Distribution System Cost Methodologies for Distributed
18 Generation, page 7, emphasis added).

19 The NREL report discussed above does not suggest that number of
20 customers should replace or supersede peak load as the only cost driver.
21 However, the empirical evidence provided in the NREL report clearly shows
22 that both the number of customers and peak load contribute to a utility's
23 investment in substations and transformers, and in overhead and
24 underground circuits. It is reasonable to conclude, then, that any ECOS
25 study that is designed to classify and allocate costs in accordance with how

1 those costs were incurred, will use a method that recognizes both the
2 number of customers and peak load as cost-causative factors with regard to
3 these primary and secondary voltage facilities.

4 ECOS studies that only recognize the costs of services and meters
5 as customer-related costs, significantly understate the costs of connecting
6 customers to the distribution system.

7

8 **Q WHAT OTHER EVIDENCE EXISTS THAT SUGGESTS THESE DISTRIBUTION**
9 **COSTS ARE DIRECTLY RELATED TO THE NUMBER OF CUSTOMERS ON**
10 **THE SYSTEM?**

11 A As I have already stated, F.A.C. Rule 25-6.0342 requires that planned
12 expansions, upgrades, or relocations of facilities be constructed to "extreme
13 weather conditions." F.A.C. Rule 25-6.064 describes how financial contributions
14 from customers (i.e., Contributions-in-Aid-of-Construction or "CIAC"), that are
15 collected to pay for a portion of the costs of these new or upgraded facilities,
16 should be treated. This rule states:

17 "All CIAC calculations under this rule shall be based on estimated
18 work order job costs. In addition, each utility shall use its best
19 judgment in estimating the total amount of annual revenues which
20 the new or upgraded facilities are expected to produce.

21 (a) ...

22 (b) *In cases where more customers than the initial*
23 *applicant are expected to be served by the new or*
24 *upgraded facilities, the utility shall prorate the total*
25 *CIAC over the number of end-use customers*

1 *expected to be served by the new or upgraded facilities*
2 *within a period not to exceed 3 years, commencing with*
3 *the in-service date of the new or upgraded facilities.”*
4 (F.A.C.. Rule 25-6.064, subpart (6), emphasis added).

5 The language in this F.A.C. rule provides unequivocal support for the idea that
6 the costs associated with providing service to customers – which is what the
7 CIAC is intended to offset – is directly proportional to the number of customers
8 being served. It is a small step to recognize that the costs that are not offset by
9 CIAC payments, i.e., costs that are recorded in FERC Accounts 364 through 368,
10 are also incurred in direct proportion to the number of customers.

11

12 **Commission’s Acceptance of MDS for**

13 **Choctawhatchee Electric Cooperative, Inc. (“CHELCO”)**

14 **Q HAS THE COMMISSION EVER ADOPTED AN ECOS STUDY THAT**
15 **INCLUDED THE USE OF AN MDS METHOD BY ANY FLORIDA UTILITY?**

16 **A Yes.** In Order No. PSC-02-1169-TRF-EC, issued in Docket No. 020537-EC on
17 August 26, 2002, the Commission approved rates for CHELCO that were based
18 on an ECOS study which used the ZI method to estimate the MDS costs, and
19 allocate them based on the number of customers.

20

21 **Q WHY DID THE COMMISSION APPROVE THE USE OF AN MDS METHOD**
22 **FOR CHELCO WHEN IT HAS NOT ALLOWED SUCH USE FOR IOUS?**

23 **A In Order No. PSC-02-1169-TRF-EC, the Commission stated:**

24 “In the past 20 years, we have consistently rejected the use of the
25 MDS classification methodology by investor-owned utilities ... In this

1 case, however, we find that CHELCO has four unique characteristics
2 that justify the use of the MDS classification methodology in its cost
3 of service study." (Choctawhatchee Electric Cooperative, Inc., Order
4 No. PSC-02-1169-TRF-EC, issued August 26, 2002 in Docket No.
5 020537-EC, page 3).

6 The first unique characteristic identified by the Commission was that "CHELCO
7 has a density of ten customers per mile, while most investor-owned utilities have
8 a density of fifty-five customers per mile or greater." (*Id.*). The Commission's
9 Order also states:

10 "In a high-density service territory, several customers may be
11 served by a single transformer, while in a sparsely populated rural
12 area there is usually one transformer for each residential account.
13 Thus, the significant costs of constructing and maintaining a mile
14 of line in a rural service territory are spread to a significantly fewer
15 number of customers." (*Id.* page 4).

16 There are a couple of problems with using relatively low customer
17 densities as a basis for approving an MDS. First, it is counterintuitive. The
18 customer densities of the IOUs identified by Staff clearly show that, on average,
19 "most" IOUs will incur the cost of connecting an additional customer five and a
20 half times more frequently than CHELCO. This strongly implies that the
21 customer-related costs incurred to connect customers to the system will be much
22 higher for the IOUs than for CHELCO. In other words, most IOUs will incur the
23 costs of transformers and secondary voltage circuits five times as often as
24 CHELCO does. It is unclear, therefore, why CHELCO's relatively low customer
25 density justifies its use of MDS methods, but the much more frequent incurrence

1 of customer-related costs of “most” IOUs does not.

2 More importantly, it is unprecedented to base adoption of the MDS
3 method on the customer density of one utility relative to another. Indeed, the
4 Commission’s allowance of the MDS method in the case of CHELCO
5 demonstrates – at the very least – that the Commission is aware that some
6 portion of the primary and secondary distribution system costs, other than those
7 related to services and meters, is customer-related. Furthermore, the
8 Commission’s acceptance of CHELCO’s ZI analysis shows that it also recognizes
9 the usefulness of such analyses to estimate this customer-related portion.

10

11 **Q WHAT IS THE SECOND UNIQUE CHARACTERISTIC OF CHELCO THAT THE**
12 **COMMISSION IDENTIFIED?**

13 **A** The second unique characteristic identified by the Commission was that
14 “CHELCO’s rural service territory is quite different from an urban investor-owned
15 utility.” The Commission explains in its order:

16 “Urban areas are normally occupied throughout the year, and
17 customers usually consume a large amount of electricity that
18 varies seasonally with their heating and cooling load. By contrast,
19 CHELCO provides service to a significant number of barns, stock
20 tanks, electric fences, hunting cabins, and vacation homes. These
21 types of customers consume small amounts of electricity during
22 the course of the year, and their usage is sporadic. A rate design
23 with a relatively low customer charge and a high energy charge for
24 these customers may not recover the costs of investment
25 necessary to serve their load.” (*Id.*).

1 This explanation is surprising in that it begins by describing how perceived
2 differences between rural and urban service territories pertain to the MDS
3 method, yet then draws a conclusion about rate design. Nothing is said to
4 address how urban/rural territory differences negate the importance of the MDS
5 in one case, or increase the importance of the MDS in the other. Furthermore,
6 the comments regarding rate design appear out of place, since the MDS is
7 specific to the ECOS study and therefore precedes, but is otherwise unrelated to
8 the rate design process.

9

10 **Reasons for Commission's Past Rejections of MDS**

11 **Q GIVEN THAT THE COMMISSION HAS APPROVED THE USE OF MDS**
12 **METHODS FOR AN ELECTRIC COOPERATIVE, WHAT REASONS HAS THE**
13 **COMMISSION GIVEN IN REJECTING THE USE OF MDS METHODS FOR**
14 **IOUS IN PAST CASES?**

15 **A** The Commission objections to the MDS have been numerous and varied. In its
16 June 10, 2002 order (Order No. PSC-02-0787-FOF-E1) issued in regard to Gulf
17 Power's 2002 rate case (Docket No. 010949-E1), the Commission rejected the
18 use of the MDS after providing the following explanations:

- 19 1. Although utility and intervenor witnesses relied on the NARUC Manual to
20 support the use of MDS, the NARUC Manual's stated purpose shows it
21 was designed to educate regarding various cost allocation methods, not
22 mandate any particular method.
- 23 2. Gulf Power provided no evidence on the specific circumstances that
24 made it choose the MDS methodology over the method approved by the
25 Commission in Gulf Power's previous rate case.

- 1 3. The MDS methodology requires construction of a hypothetical system
2 consisting of equipment that is designed to carry zero load. Therefore, no
3 real equipment equates to the costs identified by the ZI methodology.
4 The Commission has rejected MDS in the past for this very reason.
- 5 4. Prior orders by the Commission show that it was the MDS's theoretical
6 construct with which the Commission disagreed, not the end result of
7 ECOS studies that use MDS methods.
- 8 5. The MDS is internally inconsistent in that it separates out distribution
9 facilities for different treatment than transmission lines.

10 These are just a subset of the arguments against the MDS that the Commission
11 has accepted over the last 30 years. Indeed, the Commission has not only
12 rejected MDS proposals from Gulf Power, but has also rejected MDS proposals
13 from the Commission Staff, Florida Power & Light Company, Florida Industrial
14 Power Users Group, South Florida Hospital and Healthcare Association, Tampa
15 Electric Company, and Florida Power Corporation.

16

17 **Q DOES THE MDS METHODOLOGY REQUIRE CONSTRUCTION OF A**
18 **HYPOTHETICAL SYSTEM CONSISTING OF EQUIPMENT THAT IS**
19 **DESIGNED TO CARRY ZERO LOAD?**

20 **A**No. The notion that the MDS is designed to carry no load is an
21 over-simplification, and is also something of a straw-man argument. A better
22 description of the MDS is that it reflects the smallest, lowest cost distribution
23 system that *must be installed for the utility to meet its obligation to provide*
24 *service to its customers*, but does not contain costs incurred to meet the
25 customer's peak load. Therefore, the MDS methodology only requires the

1 analyst to identify the electric system components that must be installed to meet
2 whatever construction, safety and/or reliability standards are enforced by the
3 governing authorities at the time the line is installed.

4 The most realistic and accurate concept of the MDS is that it consists of
5 the network of electric lines that conform to the NESC requirements described in
6 the F.A.C.

7
8 **Q IS THE MDS INTERNALLY INCONSISTENT IN THAT IT SEPARATES OUT**
9 **DISTRIBUTION FACILITIES FOR DIFFERENT TREATMENT THAN**
10 **TRANSMISSION LINES?**

11 **A** No. It is universally understood that any electric system that carries electricity
12 from the generator to the customer must contain transmission, sub-transmission,
13 and distribution components. However, it is also widely recognized that the
14 customer-related portion of costs steadily decreases as one moves away from
15 the end-use customer toward the generator. At the transmission level, the
16 customer-related portion of costs is generally low.

17 For example, at the meter, the customer-related portion of costs is 100%.
18 Likewise, the customer-related portion of service costs is also 100%. However,
19 the customer portion of costs drops significantly at the level of primary and
20 secondary distribution lines. According to Gulf Power's analysis, the customer-
21 related portion of its primary and secondary line costs, based on Gulf Power's
22 own analysis of its distribution system, is slightly more than 27%.⁴ If Gulf
23 Power's MDS analysis method were applied to costs recorded in the

⁴Percentage found by dividing the customer-related costs identified for FERC Accounts 364-368 by total cost recorded in these FERC accounts.

1 transmission line accounts (FERC Accounts 354 through 358) it is reasonable to
2 expect the customer-related portion to be far below 27%.

3

4 **In-Depth Discussion of MDS**

5 **Q YOU HAVE DESCRIBED THE MDS PROCESS AS AN ESTIMATE OF COSTS.**
6 **IS IT A MAJOR PROBLEM THAT GULF POWER HAS ESTIMATED THE**
7 **AMOUNT OF CUSTOMER AND DEMAND-RELATED COSTS USING ITS**
8 **PLANT RECORDS?**

9 A No. In fact, utilities commonly rely on engineering and/or operations data to
10 develop percentage estimates that are then used as a proxy for cost data. This
11 is precisely the method that Gulf Power uses when it estimates the primary and
12 secondary portions of its distribution system.

13

14 **Q DO YOU AGREE WITH GULF POWER WITNESS O'SHEASY'S USE OF THE**
15 **ZI METHOD TO ALLOCATE DISTRIBUTION COSTS?**

16 A Yes. Mr. O'Sheasy's use of the ZI method is reasonable and appropriate given
17 the overwhelming evidence available today which indicates that the costs Gulf
18 Power incurs to install and maintain its primary and secondary distribution
19 systems are caused by both the number of customers on the system and the
20 peak demand of those customers.

21 This is not to say that the specific method used by Mr. O'Sheasy to
22 estimate the MDS could not be improved. It certainly could. However, all of the
23 improvements of Mr. O'Sheasy's analysis that I could propose, would result in a
24 larger share of the distribution costs being allocated on the number of customers.
25 Therefore, Mr. O'Sheasy's estimate of the MDS is conservative in the sense that

1 it understates the amount of costs that are actually caused by the number of
2 customers.

3

4 **Q DOES THE COMMISSION'S REQUIREMENT THAT ALL UTILITIES COMPLY**
5 **WITH THE NESC, SUPPORT THE CONCEPT OF THE MDS?**

6 A Yes. The Commission's requirement that all Florida utilities comply with the
7 NESC (F.A.C. Rule: 25-6.0345), and its infrastructure hardening requirement
8 entitled "Electric Infrastructure Storm Hardening (F.A.C. Rule 25-6.0342),
9 establish the specific NESC standards with which the Florida utilities must
10 comply whenever a new customer is connected to the system. Given that the
11 cost of nearly every major primary and secondary distribution system component
12 (FERC Accounts 364 through 368) is affected by these NESC requirements, all
13 Florida utilities will incur costs in direct proportion to the number of customers
14 they serve.

15 The same cannot be said with respect to demand. If the demand of an
16 existing customer increases or decreases, the cost of meeting the NESC
17 standards remains fixed.

18

19 **Q DO YOU AGREE THAT CUSTOMER ELECTRICAL DEMAND IS AN**
20 **IMPORTANT CRITERION WHEN DESIGNING A DISTRIBUTION SYSTEM?**

21 A Yes, the demand requirements that must be met are important factors in system
22 design. Distribution engineers rely on load forecasts and load flow studies to
23 identify and design distribution system upgrades or to project load growth. Local
24 peak demand of a circuit is a vital component of these forecasts and studies.
25 Further, some segments of the delivery system (but not all) will vary with

1 expected demand. However, when developing an ECOS study, other criteria can
2 be important as well. Gulf Power's ECOS study uses the ZI method to determine
3 a customer-related portion of costs associated with the Company's primary and
4 secondary distribution facilities. Therefore, it is capable of recognizing the cost-
5 causative impact of the F.A.C. rules on these facilities. Absent an MDS method,
6 a significant portion of Gulf Power's distribution costs, which are caused by the
7 number of customers on the system, will nevertheless be inappropriately
8 allocated on the basis of customer demand.

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10 **Q PLEASE EXPLAIN WHAT YOU MEAN.**

11 **A** As I said previously, the fundamental premise of a proper ECOS study is the
12 concept of *cost-causation* which is, in many cases, directly related to electrical
13 parameters like voltage level or peak demand. This is particularly true when
14 planning for maximum conditions or "worst case" scenarios. Yet, there are
15 factors besides voltage level and peak demand that can significantly affect cost.
16 A properly conducted ECOS study must consider all cost-causing factors.

17 When distribution engineers design the enhancement, upgrade or
18 extension of an electric system, they must be constantly aware of the operating
19 parameters of the system. But, it is in the construction of the distribution system
20 that the *true cause* of many distribution costs is clearly seen. Surprisingly, that
21 cause is frequently not demand.

22 An illustration helps make this point clear. Consider a customer who
23 intends to build a home on a new lot, one that does not already have electrical
24 service. This customer is cost and energy conscious and thus chooses to use as
25 many energy efficiency techniques and appliances as possible. After

1 considerable research and consultation with experts, the customer calls the utility
2 and informs it that he will require service capable of providing a maximum peak
3 demand of 2,000 watts (2 kW).

4 During the installation of the primary and secondary distribution extension
5 to the customer's home, he notices that the linemen are using conductors, poles,
6 cross-arms, and components identical to those serving the much larger, and less
7 efficient, home down the street. After more investigation, the customer learns
8 that the distribution extension to his home is capable of carrying far greater
9 demand than his home was designed to use. When he informs the utility of this
10 "error," the utility explains that it cannot install wires smaller than a certain size or
11 hang them below a certain height. In short, there are specified minimum
12 standards that the utility must meet that are wholly unrelated to the new home's
13 reduced demand.

14 This illustration demonstrates that although utilities design and install
15 distribution equipment to satisfy their customers' need for electricity, there are
16 factors other than electrical demand that force them to incur costs. Safety and
17 reliability are as critical to every phase of design and construction as demand.
18 As one reviews the cost of the distribution system nearest the customer (that
19 portion from the distribution system that includes primary voltage radial lines, line
20 transformers and the network of secondary voltage lines), the cost incurred to
21 comply with safety and reliability standards begins to outweigh the cost of
22 meeting electrical demand.

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1 Q HAS THE COMMISSION ADOPTED THE NESC STANDARDS IN THE F.A.C.?

2 A Yes. F.A.C. Rule 25-6.0345 – Safety Standards for Construction of New
3 Transmission and Distribution Facilities states:

4 “The Commission adopts and incorporates by reference the 2002
5 edition of the National Electrical Safety Code (ANSI C-2) [NESC],
6 as the applicable safety standards for transmission and
7 distribution facilities subject to the Commission’s safety
8 jurisdiction. For electrical facilities constructed on or after
9 February 1, 2007, the 2007 NESC shall apply. Electrical facilities
10 constructed prior to February 1, 2007, shall be governed by the
11 edition of the NESC specified by subsections 013.B.1, 013.B.2,
12 and 013.B.3 of the 2007 NESC. Each investor-owned electric
13 utility, rural electric cooperative, and municipal electric system
14 shall, at a minimum, comply with the standards in these
15 provisions.” (F.A.C. Rule 25-6.0345, subpart (1), emphasis
16 added).

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1 **Q WHAT IS THE PURPOSE OF THE NESC?**

2 A Section 1, Part 010, of the NESC states:

3 “The purpose of these rules is the practical safeguarding of
4 persons during the installation, operation, or maintenance of
5 electric supply and communication lines and their associated
6 equipment. They contain *minimum provisions considered*
7 *necessary* for the safety of employees and the public. They are
8 not intended as a design specification or an instruction manual.”

9 (Emphasis added).

10

11 **Q DOES THE NESC ALSO ESTABLISH STANDARDS FOR THE ELECTRICAL**
12 **DEMAND EACH COMPONENT MUST BE CAPABLE OF CARRYING?**

13 A Not directly. To my knowledge, the only situation where the NESC covers
14 something like this is in the case of grounding wires where the NESC sets the
15 “short time ampacity adequate for a fault current.”⁵ Yet even here, the purpose of
16 the grounding wire is to provide safety or enhance reliability rather than to serve
17 electrical load.

18

19 **Q ARE MDS METHODS USED FOR ALLOCATING DISTRIBUTION COSTS IN**
20 **OTHER STATES?**

21 A Yes, it is not uncommon outside of Florida. My research indicates MDS methods
22 are currently, or have been approved by at least 17 state commissions.

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⁵Section 9, Subsection 93.C., Ampacity and Strength.

1 **Q WHAT DO YOU RECOMMEND?**

2 A The Commission should accept Gulf Power's use of the ZI method to estimate
3 the customer-related costs associated with the Company's primary and
4 secondary distribution system. By recognizing the MDS in its ECOS study, Gulf
5 Power has obtained a reasonable, yet understated, estimate of costs associated
6 with the MDS. The Commission should also accept Gulf Power's classification of
7 the costs identified by its ZI analysis as customer-related, and its allocation of
8 these costs based on the number of customers in each class.

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10 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

11 A Yes, it does.

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Qualifications of David L. Stowe

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Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A David L. Stowe. 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 SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the Kansas State University's College of Electrical and Computer Engineering in 1987, with a Bachelor of Science degree in Electrical Engineering. Following my graduation, I worked with the Kansas Corporation Commission ("KCC") as a Utilities Engineer. My responsibilities included the review and engineering analysis of utility filings, investigations of compliance with the Commission's Orders and State laws, and filing and defending testimony regarding those filings. In addition, I served as Geographic Information Systems Coordinator as the KCC digitized and automated its utility facilities and territory maps from the original velum sheets.

In April of 1993, I accepted a position with the Missouri Public Service Commission where, again in the capacity of a Utilities Engineer, focused primarily on depreciation, jurisdictional allocations, and production cost modeling. My employment with the Commission also allowed me to complete the requirements for Professional Engineer registration. I acquired my certificate for

1 Professional Engineering registration in 1996.

2 From October 1995 until January 2002, I developed my expertise in
3 computer engineering and communications; first acting as a Unix System
4 Administrator and Oracle DBA with Kansas City Power and Light, and later
5 offering both hardware and software consulting services to corporations with
6 enterprise-wide application requirements with Digital Equipment Corporation and
7 Compaq. During this time, I was also the president and owner of a company that
8 installed analog and digital communication systems in cellular phone towers.

9 In January of 2002, I joined the Analytic Services Department of Aquila,
10 Inc. as a Senior Regulatory Analyst where I was primarily responsible for
11 developing and maintaining cost of service models for each of Aquila's electrical
12 territories. In addition, I was solely responsible for completing associated
13 engineering studies to determine the P/S portions of each subsidiary's
14 distribution systems, calculating the zero intercept values for the subsidiaries'
15 poles, conductors, conduits, and transformers, performing customer impact
16 analyses, and assisting in rate design.

17 In October of 2007, I joined Brubaker & Associates, Inc. as a consultant.
18 Since that time, I have assisted on cost of service, revenue requirement, and
19 tariff issues in Colorado, Illinois, Kansas, Michigan, Missouri, Montana, New
20 York, Oklahoma, Wisconsin and Wyoming.

21 I have testified before the State Commissions of Colorado, Illinois,
22 Kansas, Michigan and Missouri.

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

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