Dianne M. Triplett
DEPUTY GENERAL COUNSEL

March 2, 2026

VIA ELECTRONIC FILING

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Petition For Limited Proceeding to Approve Large Load Tariff by Duke Energy Florida, LLC, Docket 20250113-EI*

Dear Mr. Teitzman:

On behalf of Duke Energy Florida, LLC ("DEF"), please find enclosed for electronic filing:

- Rebuttal Testimony of Matt Chatelain;
- Rebuttal Testimony of Kourtni Yager; and
- Rebuttal Testimony of Steve Wishart.

Thank you for your assistance in this matter. Should you have any questions, please feel free to contact me at (727) 820-4692.

Sincerely,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/mh
Enclosures

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CERTIFICATE OF SERVICE
Docket No. 20250113-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 2nd day of March, 2026, to the following:

/s/ Dianne M. Triplett
Dianne M. Triplett

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE LARGE LOAD TARIFF

REBUTTAL TESTIMONY OF

MATTHEW CHATELAIN

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20250113-EI

March 2, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Chatelain, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. Have you previously filed direct testimony in this docket?

A. Yes.

Q. Have your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the intervenor testimony of Office of Public Counsel ("OPC") witness Nelson. Specifically, I will address Mr. Nelson's arguments and recommendations around the overall framework of customer protections in the Large Load Customer Policy ("LLCP") and Large Load Customer Agreement ("LLCA") proposal, including policy applicability, early termination fees/penalty, minimum bill calculation, and minimum contract terms. I will also touch on the idea of including flexible connections that Mr. Nelson introduced.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your testimony.

A. My testimony explains that the Company's proposed LLCP is reasonable, well-structured, and necessary to protect existing customers while enabling the Company to serve anticipated large load customer demand. The Commission should reject Mr. Nelson's recommendation to lower the proposed applicability threshold of the LLCP because existing tariffs already address smaller, 50 MW customers, and keeping the threshold at 100 MW as the Company proposes better reflects the scale of today's large load customer requests. The early termination provisions and minimum bill design appropriately recover fixed costs. Flexible load ramp periods support efficient system planning and avoid premature investment, while fixed limits are unnecessary. The Commission should similarly reject Mr. Nelson's proposals to require flexible connections or regulate behind-the-meter resources because potential large load customers require firm service. In addition, flexible connections do not reduce DEF's required investment for firm service. Finally, delaying approval of the LLCP to evaluate speculative alternatives would leave existing customers insufficiently protected from the risks associated with current firm large-load requests.

II. LLCP SIZE THRESHOLD

Q. OPC Witness Nelson recommended lowering the threshold for application of the LLCP from 100 MW to 50 MW or greater of firm demand.[1] Do you have a response to this recommendation?

A. Yes. As discussed in discovery and in my deposition, the Company already has general provision coverage for a customer with monthly maximum demand of 50 MW or greater, excluding existing customers. Mr. Nelson's recommendation to lower the policy applicability would impact existing customers that already have maximum demand greater than 50 MW and would conflict with the special provisions within currently available rate schedules. Additionally, Mr. Nelson's reliance on historical information for average data centers in Virginia does not reflect the current market conditions for data center capacity requests, where large load requests routinely range from 100 MW to over 1 GW and continue to increase in scale. Nor is the average data a reflection of the inquiries that the Company has from prospective customers to date as reflected in the Company's response to OPC ROG 2, Question 24, part c, showing 13.2 GW of requested capacity for 19 large load projects. The Company's LLCP is

[1] Nelson Testimony, p. 40, l. 5-8.

reasonable and should only apply to customers with load of 100 MW or greater, as proposed.

III. TERMINATION PAYMENT AND MINIMUM BILL

Q. Mr. Nelson states that DEF's early termination payment is more lenient than most of the recent large load policies[2]. Do you agree with his assessment?

A. No. The alternative requirement comparisons that Mr. Nelson points to in other large load tariffs, namely 1) all minimum monthly bills for the duration of the contract, or 2) the remaining undepreciated value of facilities whose costs have been directly assigned to the specific customer, typically carry mitigation provisions, which invites litigation around what the utility may actually recover from a customer. The Company-proposed termination fees and damages ensure timely collection and provides fixed cost recovery for two or three years plus the notice period requirements (which ranges from two to five years). This structure results in a range of four to eight years of minimum bill coverage, depending on the timing of the termination event and the required notice period in the executed LLCA. The notice period provides sufficient time for the Company to reincorporate assets into system planning and redeploy them efficiently to serve other customers. The notice period also increases the amount of minimum bills the customer must pay, in the event of an early termination.

Q. Mr. Nelson states that the minimum bill will drop considerably if a customer exits a contract early or operates a lower-than-expected load factor and shows a

[2] Nelson Testimony, p. 41, l. 11-12.

comparison[3] of the average and minimum bill for a 1,000 MW and 100 MW customer. How do you respond to this assertion?

A. The design of the LLC-1 rate schedule recovers fixed costs primarily through a demand charge aligned with take or pay provisions applied to the requested contract capacity. The Minimum Billing Demand will remain unchanged if a customer operates at a lower-than-expected load factor, because the minimum bill calculation is based on the contract capacity, which would not change with a customer's actual operations. The bulk of the volumetric charge and part of the demand charge shown both in the corrected[4] Table 2 and again in Table 3 of Mr. Nelson's direct testimony improperly includes fuel and other clause rates. The conclusions that Mr. Nelson draws from his comparison of average to minimum bills are nonsensical. In the context of a termination scenario, the percentages of an average bill versus a minimum bill in Mr. Nelson's testimony comparison including fuel and clause volumetric charges would be improper ratemaking and unfair to include in the minimum bill calculation, as fuel and clause rates are not related to the generation and transmission costs that would determine sufficiency of a large load customer termination fee. Additionally, Mr. Nelson's use of the hypothetical rates in LLC-1 does not demonstrate insufficient recovery of an undefined cost of stranded assets, as the COSS used for the development of the LLC-1 rates does not include incremental costs for generation or transmission. It would be improper to draw any realistic conclusion from applying these rates to stranded cost recovery, other than to say if the Company had the capability to serve the hypothetical

[3] Nelson Testimony, pp. 45-46.
[4] During Mr. Nelson's deposition, he produced a corrected table.

1 GW customer using current system resources, then under the early termination provision of the policy the Company would receive unmitigated termination fees ranging, at a minimum, from $352.8M (2 years of billings + 2 years of notice) up to $705.7M (3 years of billings + 5 years of notice); coupled with the termination notice provisions, the Company would have ample time to reassess the system resource plan. Using the proposed embedded cost methodology, any incremental costs to serve large load customers would raise the base rates for LLC-1 based on the class cost of service allocation and make the termination fee larger.

IV. LOAD RAMP

Q. Mr. Nelson recommends setting a five-year limit on the load ramp period.[5] Do you agree with the recommendation?

A. No. I disagree with the need for a defined limit for the load ramp period. By allowing flexibility to align the timing of system resource planning with a customer's actual expected load growth, the Company is purposefully implementing fair recovery of potential incremental resources that may or may not be needed in every scenario. For example, assume that a prospective customer requests 500 MW in total, but based on timing for their construction, would only need 200 MW in the first 4 years, and the remaining 300 MW in year 7. In this scenario, if the Company could serve the first 200 MW with current assets, it could wait to determine how to serve the remaining 300 MW until when the customer needed that additional power. The Company could therefore efficiently plan with a scenario that matches the customer's actual needs,

[5] Nelson Testimony, p. 52, l. 18-19.

rather than being bound to an arbitrary timeline to have the system ready to serve 500 MW before it would otherwise be needed.

V. FLEXIBLE INTERCONNECTION

Q. Please summarize Mr. Nelson's arguments regarding flexible connections.

A. Mr. Nelson first claims that requiring large load customers to take non-firm service (i.e., "flexible connections") is beneficial because it allows the utility to defer or avoid system investment.[6] He next argues that other jurisdictions utilize flexible connections, and that data center customers are more open to flexible connections, in particular because they can utilize behind the meter (BTM) generation.[7] Finally, he recommends that the Commission not approve DEF's tariff until the Commission has developed a flexible connections tariff in a separate proceeding.[8]

Q. How do you respond to his first argument that use of flexible connections can avoid system investment?

A. I disagree with Mr. Nelson. Flexible connections cannot avoid system investments. While DEF may be open to utilizing flexible connections in the future and may file a future amendment to the tariff to that end, or address in particular LLCAs pursuant to the negotiating flexibility, given DEF's size and the potential magnitude of the data center customers' load (individually or in aggregate), it is not realistic to open a flexible connection tariff to all applicants. DEF will need to evaluate the relative size of the

[6] Nelson Testimony, p. 54.
[7] Nelson Testimony, p. 61-62.
[8] Nelson Testimony, p. 62, l. 17-19.

load and its impact on the system. A mismatch between load and system generating capacity due to large flexible loads would result in restrictions on the Company's ability to schedule necessary maintenance on the generation fleet and a risk of extended curtailment either for the large load customer or potentially for other demand response customers. DEF may consider such arrangements on a limited basis as a bridge to accommodate a requested load ramp or in other (also limited) cases make the arrangement longer term after assessing the impact on system operation.

Q. Do you agree that data center customers are more open to flexible connections?

A. No. Mr. Wishart, in his rebuttal testimony, discusses the willingness of data center customers generally to accept flexible connections. As for DEF specifically, to date potential large load customers have not requested non-firm service. In DEF's experience, large load customers, specifically those operating data centers, are generally averse to non-firm load arrangements. However, one of the reasons that DEF's LLCP includes flexibility when negotiating the LLCA is to allow the Company to add additional provisions like flexible connections, if and when there is an operational need, a shift in customer interest, or technological advances that enhance the Company's ability to serve large load customers.

Q. Mr. Nelson points to Mr. Sideris' comments in a recent earnings call to claim that Duke Energy has experience with flexible connections. How do you respond?

A. Duke Energy Carolinas has implemented limited-duration curtailment provisions in certain of its recent large load supply agreements, but such provisions are only in place for a limited period of time. Duke Energy Carolinas continues to plan its system to meet such load on a firm basis over the long-term, consistent with the expectations of its customers. This is similar to what DEF may do in Florida if it makes sense to do so, but as explained above, the Commission should not force the Company to require all large load customers to accept flexible connections for the entire term of their contract.

Q. How does the Company respond to Mr. Nelson's arguments regarding BTM resources facilitating flexible connections?

A. While it is true that these customers do appear willing to provide behind the meter back up power, typically in the form of diesel generators, as Mr. Nelson points out, the ability for the large load customers to provide primary power using BTM resources could reduce the requested firm service that the Company is requested to serve and as such would be outside of the necessary scope of the proposed policy. As such, dictating the form or use of BTM resources is not a necessary part of a robust and protective framework for competently serving large load customer requests. Mr. Nelson also points out that many BTM resources are not permitted for use except during grid emergencies. Replacing these resources with units with greater operational flexibility would come at significantly higher cost to the customer.

DEF cannot prevent a customer from providing BTM resources. However, the utility must still manage the customer's need for grid support either because the customer chooses to economically dispatch the BTM resources, or because the customer requests grid support during BTM unit outages. In either case, the utility is supplying the offsetting capacity to support the customer, potentially at a higher cost due to low utilization.

Q. Should the Commission accept Mr. Nelson's recommendation to delay approval of DEF's tariff until a flexible connections tariff is approved in a separate proceeding?

A. No. Because, as Mr. Nelson acknowledges,[9] the Company has an obligation to serve customers requesting service, Mr. Nelson's inclusion of an idealistic version of flexible connections as a reason to delay approval leaves existing customers insufficiently protected from the risks present today from the very real firm load requests the Company is receiving. The Company is not precluded from considering flexible connections in the future, as explained above.

VI. <u>LLCA FILING REQUIREMENT</u>

Q. How do you respond to Mr. Nelson's recommendation that all LLCAs be filed with the Commission for review and approval?

A. This is simply unnecessary. The point of having an approved form tariff contract is to give DEF and prospective large load customers certainty regarding terms that will apply to DEF's provision of service. If the Commission approves the form, there is simply no further action that the Commission must take to review and approve executed LLCAs. If DEF must submit these LLCAs and parties may make arguments about

[9] Nelson Deposition, p. 14, l. 21 through p. 15, l. 5.

additional terms that could or should be modified or added, this will create uncertainty, unnecessary delay, and could discourage potential customers from executing LLCAs.

VII. CONCLUSION

Q. Did you respond to every contention regarding the Company's proposed plan in your rebuttal?

A. No. My silence on any particular assertion in Mr. Nelson's testimony should not be read as agreement with or consent to that assertion.

Q. Should the Commission approve the Company's tariff as filed?

A. Yes. As explained in the Company's direct and rebuttal testimony, and supported by its discovery responses, the Company's filing is a reasonable, measured approach to accommodate new large loads by appropriately balancing the interests of these customers and the other existing and future DEF customers. By contrast, Mr. Nelson's testimony regarding the "ideal" large load tariff represents overly restrictive terms that even he admits have not all been adopted completely by any one utility.[10]

Q. Does that conclude your testimony?

A. Yes.

[10] Nelson Deposition, p. 39, l. 17-22.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE LARGE LOAD TARIFF

REBUTTAL TESTIMONY OF

KOURTNI YAGER

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20250113-EI

March 2, 2026

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Kourtni Yager. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed direct testimony in this docket?

A. Yes.

Q. Have your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the Office of Public Counsel ("OPC") witness Nelson. Specifically, I will address the impact of cost allocation on customer protections and benefits, the impact of changing economic conditions on cost allocation, and the application of an incremental generation charge ("IGC"). My silence on any particular assertion in Mr. Nelson's testimony should not be read as agreement with or consent to that assertion.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your testimony.

A. My testimony shows that:

- Along with DEF's cost allocation methodology, DEF's class revenue apportionment and revenue collection (as ultimately approved by the Commission) ensures fair and reasonable treatment for all customers;
- DEF's embedded cost allocation methodology is a fair and reasonable approach to allocating system costs;
- DEF's proposal is consistent with longstanding Commission principles regarding cost causation, gradualism, and rate stability;
- DEF's embedded cost allocation methodology should not be used to moderate the impact of changing economic conditions; and

- Allocating embedded costs to a large load customer and applying an incremental generation charge for the same load improperly concentrates costs on the large load customer.

II. THE IMPACT OF COST ALLOCATION ON CUSTOMER PROTECTIONS AND BENEFITS

Q. Do you agree with Mr. Nelson's assertion[1] that whether existing customers are protected from short-term rate impacts and whether potential benefits to other customers materialize over the long-term are closely related to how costs are allocated to new customers?

A. While I agree that cost allocation is a contributing factor to both short- and long-term rate impacts to customer classes, it is important to note that there are other factors affecting the balance of short-term protections for current customers and long-term benefit realization.

Q. Please explain the other factors affecting this balance.

A. Two important factors impacting all customers are revenue apportionment and revenue collection. Revenue apportionment determines how total revenues are assigned to customer classes through DEF's rates. Although informed by class cost of service studies, revenue apportionment does not necessarily track class cost-of-service results. Any divergence between cost responsibility and revenue assignment primarily reflects the Commission's longstanding application of the principle of gradualism,

[1] Nelson Testimony, p,. 5, l. 2-5.

which is intended to moderate the timing and magnitude of rate impacts. This approach represents a deliberate regulatory judgment to balance rate stability, fairness, and reasonableness across customer classes, rather than an outcome driven solely by cost allocation. Consistent with this framework, the Commission retains full authority to determine the level of revenues collected from each customer class. Changes to DEF's class cost allocation alone would not ensure the customer protections Mr. Nelson suggests, because revenue impacts ultimately depend on Commission approved revenue apportionment decisions.

Q. Are there additional elements of DEF's Large Load Filing that impact revenue collection?

A. Yes. Many of the customer protections proposed in DEF's September 5, 2025, filing are aimed at ensuring near- and long-term revenue collection from potential large load customers. These include, but are not limited to contract term length, termination notification requirements and fees, security requirements, CIAC modifications, and minimum bill provisions. These provisions allocate customer specific risks to the customers that create them.

III. <u>THE IMPACT OF CHANGING ECONOMIC CONDITIONS ON COST ALLOCATION</u>

Q. Does Mr. Nelson assert that data centers are increasing the cost of generation assets across the electric utility industry?

A. Yes. Mr. Nelson asserts[2] that the growth of data centers is contributing to rising generation costs across the industry and ultimately that this trend warrants changes to utility cost allocation methodology.

Q. Does the existence of industry-wide generation cost increases, by itself, demonstrate that DEF's cost allocation methodology is flawed?

A. No. Industry-wide increases in the cost of new generation resources do not demonstrate that DEF's embedded cost allocation methodology is unreasonable or inconsistent with cost causation principles. Cost allocation determines how the costs of the existing system are shared among customer classes; it does not determine whether new costs arise or what future investments are required.

Q. Does DEF believe that rising generation costs should be addressed through changes to cost allocation?

A. No. Rising generation costs should be addressed through future resource planning decisions and through general rate cases, where projected investments, revenues, and costs can be evaluated comprehensively. Cost allocation should remain focused on fairly distributing the costs of the system that exists at a given point in time.

Q. What are the long-term benefits of embedded cost allocation when new load is added to the system?

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[2] Nelson Testimony, pp. 16-21.

A. Over the long term, embedded cost allocation allows all customer classes to share both the costs and benefits of system growth. Large load customers can increase system load factors, improve utilization of existing assets, and spread fixed costs over a broader base. As new investments become part of the embedded system, their costs are allocated across all customers that use and benefit from those assets. All customers benefit when the cost of the grid infrastructure is spread over higher energy usage.

Q. Does DEF believe large load customers will ultimately contribute to system-wide benefits?

A. Yes. While the timing of costs and benefits may differ, large load customers are expected to contribute to improved system utilization and economies of scale over time, consistent with the principles underlying embedded cost allocation. Using the protections proposed in its filing, DEF seeks to balance short-term risks with long-term benefits for all customers.

Q. How does DEF propose to manage those short-term risks?

A. DEF proposes to manage short-term risks through contractual provisions proposed in this filing, including contribution in aid of construction (CIAC) requirements, minimum demand requirements, security and collateral provisions, termination notice requirements, and early termination payments. These provisions are specifically designed to address customer-specific risks without altering the underlying cost allocation methodology.

Q. Why is this approach preferable to modifying cost allocation?

A. Contractual provisions directly address the risks created by individual customers, whereas changes to cost allocation would broadly affect all customers regardless of whether they cause those risks. Managing short-term risks through contracts preserves stable cost allocation while protecting customers from near-term exposure.

IV. <u>INCREMENTAL GENERATION CHARGE</u>

Q. Mr. Nelson recommends the use of incremental generation charges.[3] Does DEF agree with that recommendation?

A. No. DEF does not agree that applying incremental generation charges on top of embedded cost recovery is appropriate.

Q. Please explain the conflict created by layering incremental generation charges over embedded costs.

A. Imposing an incremental generation charge on a specific customer class would require those customers to pay both their allocated share of embedded generation costs and an additional charge for new generation resources. This approach would improperly overstate the impact of that class's load within the embedded cost allocation framework by attributing historical embedded generation costs to load that is purportedly being served by incremental generation. As a result, this misalignment would tend to under-allocate embedded generation costs to other customer classes while improperly concentrating costs on the large load class.

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[3] Nelson Testimony, p. 63, l. 9.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE LARGE LOAD TARIFF

REBUTTAL TESTIMONY OF

STEVEN W. WISHART

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20250113-EI

March 2, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven W. Wishart. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Have you previously filed direct testimony in this docket?

A. Yes.

Q. Have your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony of Mr. Ron Nelson regarding Duke Energy Florida's ("DEF") proposed Large Load Customer Policy ("LLCP") and associated tariff provisions. Specifically, I address Mr. Nelson's recommendations concerning cost allocation methodology, transmission cost responsibility, minimum billing provisions, termination fees, security collateral, load ramp structure, and flexible interconnection concepts. I explain why DEF's proposal appropriately balances cost causation principles, risk mitigation, and long-term customer benefits, and I demonstrate that many of Mr. Nelson's characterizations of utility practice and industry trends are incomplete or overstated. My silence on any particular assertion in Mr. Nelson's testimony should not be read as agreement with or consent to that assertion.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your testimony.

A. Mr. Nelson acknowledges several important economic principles that ultimately support Duke Energy Florida's proposal, including the existence of long-term benefits under an average embedded cost framework and the need for reasonable safeguards to mitigate stranded cost risk. However, his recommendations would impose more restrictive requirements than are supported by cost causation principles or consistent with prevailing utility practice.

In my testimony, I demonstrate that average embedded ratemaking remains an appropriate and widely used framework for serving large loads when combined with contractual protections. I explain that Mr. Nelson's examples from other jurisdictions do not establish a national shift away from embedded cost allocation. I further show that his proposals regarding transmission cost assignment, minimum billing volumes, termination fees, security collateral, load ramp limitations, and flexible connections are either inconsistent with established ratemaking principles or more restrictive than comparable tariffs adopted elsewhere.

Based on the record and industry experience, I conclude that DEF's proposed Large Load Customer Policy appropriately balances ratepayer protection, economic competitiveness, and long-term system benefits and should be approved.

II. INCREMENTAL VS AVERAGE EMBEDDED RATE MAKING

Q. Have you reviewed Mr. Nelson's discussion of incremental versus average embedded cost allocation approaches?

A. Yes. I have reviewed Mr. Nelson's discussion of incremental and average embedded cost allocation approaches. In this portion of his testimony, he accurately describes the conceptual distinction between allocating only incremental costs to new customers versus allocating costs using an average embedded cost methodology.[1]

[1] Nelson Direct at 6:22–32; 7:1–9.

Q. Do you agree with Mr. Nelson's description of the tradeoffs between these approaches?

A. In general, yes. Mr. Nelson correctly notes that allocating incremental costs to new customers can protect existing customers from short-term rate impacts and potential stranded cost risks. He also correctly observes that if all costs are directly assigned to large load customers, existing customers may not share in potential long-term rate reductions that can result from spreading fixed system costs over a larger billing determinant base.[2]

These observations reflect recognized policy considerations. The regulatory question is how to balance risk mitigation and long-term system benefits in a manner that is consistent with cost causation principles and established ratemaking practice.

Q. Mr. Nelson suggests that data center growth is unprecedented and that traditional average embedded ratemaking was not designed for such large load growth. How do you respond?

A. While recent data center growth has been significant, this issue has been examined in detail in Virginia, which hosts the largest concentration of data center load in the world. The Virginia Joint Legislative Audit and Review Commission, or JLARC, conducted a comprehensive review of the impacts of data center growth on electric infrastructure, cost allocation, and retail rate equity. The JLARC report is included as Exhibit RN-3 in his testimony.

[2] Nelson Direct at 6:28–32.

The JLARC report concluded that "Current rates appropriately apportion costs to classes and customers responsible for incurring them including large loads like data centers, which means there has been no historic cost shifting based on our analysis."[3]

The report further stated that "it is possible to scale the existing, embedded (average cost based on existing infrastructure) rate structure to accommodate data center loads accounting for the marginal costs to serve that new load in a manner that is equitable for existing ratepayers," while acknowledging that doing so requires careful calibration.[4]

Accordingly, the principal legislative study in the jurisdiction with the most extensive data center growth in the country did not conclude that average embedded ratemaking is inherently inappropriate. Rather, it concluded that the framework can function equitably when properly implemented.

Q. What does that imply for this proceeding?

A. It demonstrates that the presence of significant data center growth does not, by itself, justify abandoning established embedded cost ratemaking principles. The legislative review conducted in Virginia concluded that existing rate structures appropriately allocate costs and that embedded cost frameworks can accommodate data center growth in an equitable manner.

[3] JLARC Report, Exhibit RN-3 at 19.
[4] Id.

The focus in this proceeding should therefore be on calibration and risk management, not on the premise that traditional cost allocation methodologies are inherently unsuitable for large loads.

Q. Have you reviewed Mr. Nelson's discussion of potential long-term benefits from using an average embedded cost allocation approach?

A. Yes. Mr. Nelson acknowledges that sustained large load growth can produce long-term rate benefits for other customers under an embedded cost framework. He explains that as incremental investments depreciate and fixed system costs are spread over a larger billing determinant base, rates can decline relative to what they otherwise would have been.[5] He further acknowledges that a "breakeven point" exists at which the large load customer's contribution to fixed cost recovery exceeds any initial marginal cost differential.[6]

This description reflects the fundamental economics of integrated electric utility systems and confirms that embedded cost ratemaking is capable of producing long-term system benefits when load is sustained.

Q. Does Mr. Nelson's acknowledgment of a breakeven period undermine the embedded cost framework proposed by DEF?

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[5] Nelson Direct at 10:15–23 and 11:1–8

[6] Id. at 10:15–23

A. No. The existence of a breakeven period does not invalidate embedded cost ratemaking; it reflects the long-lived nature of utility investments. The relevant policy question is not whether a breakeven period exists, Mr. Nelson concedes that it does, but whether appropriate safeguards are in place to ensure the load remains on the system long enough for those benefits to materialize.[7]

DEF's proposal includes contractual protections such as minimum billing demand requirements, security provisions, and Contribution In Aid of Construction ("CIAC") authority that materially mitigate risk during the initial investment period. Accordingly, Mr. Nelson's own testimony supports the conclusion that embedded cost ratemaking, when combined with reasonable safeguards, can balance near-term risk and long-term system benefit.

Q. Mr. Nelson states that other jurisdictions are "moving away" from the average embedded cost methodology for large loads. Do you agree with that characterization?

A. No. Mr. Nelson's characterization overstates the degree of uniformity among jurisdictions. While some utilities have proposed hybrid or incremental cost components in response to rapid load growth, there is no national consensus abandoning embedded cost ratemaking.[8]

[7] Id. at 11:1–12

[8] Nelson Direct at 12:14–22

In fact, several vertically integrated utilities experiencing substantial data center growth, including Dominion Energy Virginia, continue to rely primarily on average embedded cost allocation principles in their retail rate structures, supplemented by contractual protections and planning safeguards. The continued use of embedded cost methodologies in those jurisdictions demonstrates that embedded ratemaking remains a viable and widely accepted regulatory framework.

Q. Mr. Nelson cites several jurisdictions as evidence that utilities are moving away from average embedded cost ratemaking. Do his examples demonstrate a general shift away from embedded cost allocation?

A. No. Mr. Nelson's examples do not demonstrate a broad movement away from average embedded cost ratemaking.[9] Rather, they reflect jurisdiction-specific responses to rapid load growth, many of which are hybrid approaches, pending proposals, or settlement-based outcomes.

For example, the Georgia Power matter he cites does not adopt a discrete incremental cost pricing methodology. Instead, it reflects a stipulated agreement in a resource certification context that emphasizes the substantial revenue contribution from large-load customers and the expectation that such revenues will place downward pressure on rates. It does not represent a wholesale abandonment of embedded cost allocation principles.

[9] Nelson Direct at 12:14–22 and 18:1–21:21

Similarly, the Wisconsin Electric proposal referenced by Mr. Nelson involves a very large customer class exceeding 500 MW and includes structural features that effectively ring-fence costs associated with those customers. That proposal is materially different from DEF's Large Load Customer Policy and, in many respects, resembles the creation of a quasi-separate utility framework for extremely large loads.

The Oregon example is legislative in nature. House Bill 3546 directs the Commission to establish a separate class for large energy use facilities and to mitigate risk, but it does not prescribe a specific incremental pricing methodology.[10] Implementation remains subject to future Commission proceedings, and the statutory language is broad and flexible.

The Arizona Public Service proposal cited by Mr. Nelson remains pending and has not been approved by the Arizona Corporation Commission. Moreover, the proposal relates to a particular rate case and does not represent a permanent change to Arizona's cost allocation framework.

Finally, the FPL approach is best characterized as a hybrid or "and pricing" structure, in which customers are responsible for specific incremental costs in addition to paying average embedded system costs. It is not a pure incremental cost allocation methodology.

[10] A-Engrossed House Bill 3546, §§ 2–5 (2025) https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled

Taken together, these examples demonstrate regulatory experimentation and risk mitigation efforts tailored to local conditions, not a uniform migration away from embedded cost ratemaking. As discussed in my Direct Testimony, the utilities I identified, with the limited exceptions of Florida Power & Light and Wisconsin Electric Power Company, continue to rely on average embedded cost principles in establishing rates for large load customers. Mr. Nelson's selected examples do not demonstrate a broad industry movement away from embedded cost ratemaking. To the contrary, outside of a small number of specific proposals in individual jurisdictions, electric utilities across the country continue to use average embedded cost methodologies as the foundational basis for rate design.

III. ARE DATA CENTERS INCREASING BILLS FOR OTHER CUSTOMERS?

Q. Mr. Nelson cites Georgia Power's approximately $15 billion in generation investment associated with data center-driven demand growth. Does that figure, standing alone, demonstrate that customer bills will increase?

A. No. A capital investment figure, by itself, does not establish whether customer bills will increase. The relevant inquiry is whether the annual revenue requirement associated with that investment exceeds or is offset by the annual revenue contributed by the new large load customers.

A $15 billion investment must be evaluated in terms of its annual revenue requirement, return, depreciation, taxes, and O&M, and compared to the incremental revenues generated by the data centers driving that investment. Mr. Nelson does not perform that comparison. Without evaluating revenue contribution relative to cost recovery, the investment total alone does not demonstrate rate pressure.

Q. Mr. Nelson quotes the PJM Independent Market Monitor as stating that "data center load growth is the primary reason for recent and expected capacity market conditions." Does that statement establish that data centers are the primary driver of rising electric rates?

A. No. The quoted statement refers specifically to conditions in PJM's forward capacity market and the factors influencing recent capacity auction clearing prices. Capacity market outcomes are affected by numerous variables, including generator retirements, reserve margin tightening, interconnection delays, fuel price expectations, and broader market supply-demand dynamics.

Moreover, capacity market prices represent only one component of total retail electric rates. A statement regarding capacity market conditions does not, by itself, demonstrate that data centers are the primary driver of overall retail rate increases.

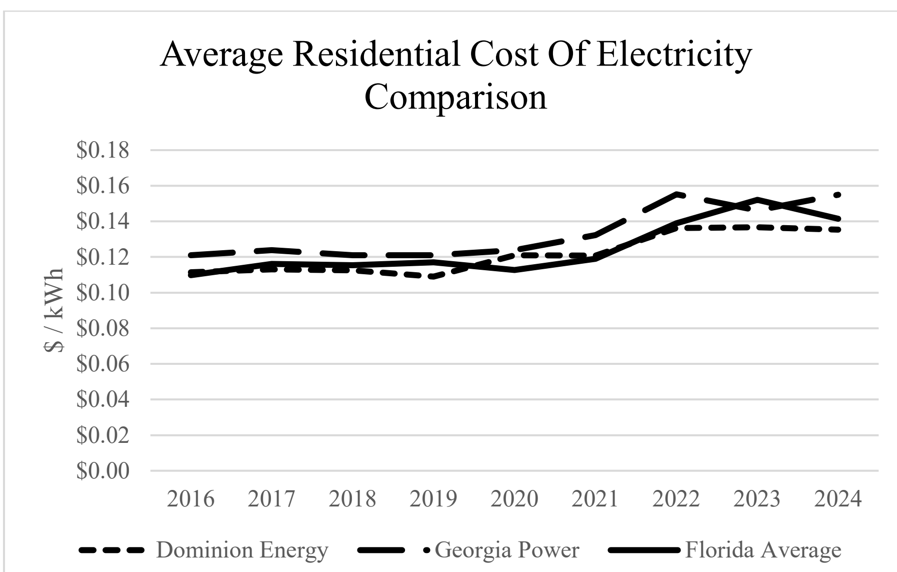
Finally, PJM operates under a regional transmission organization market structure with centralized capacity auctions. DEF operates in a vertically integrated planning and ratemaking framework. Outcomes observed in PJM's market design are not directly transferable to Florida's regulatory structure. Mr. Nelson in his deposition conceded that there are different methods for setting capacity prices in an RTO as compared to a non-RTO region like Florida.[11] Accordingly, the cited statement does not establish that DEF's customers will experience similar rate impacts.

Q. Is there empirical evidence that large data center markets have experienced disproportionate rate increases?

A. No. In fact, publicly available data show that average residential rates in the two largest data center markets in the United States, Dominion Energy Virginia and Georgia Power, have increased less over the past decade than Florida's average residential rates.

As shown in the figure below, residential rates in Virginia and Georgia have risen more gradually over the 2016–2024 period than the Florida average, despite Virginia and Georgia experiencing substantial data center-driven load growth and adhering to the traditional averaged embedded cost methodology.

Figure R-1: Average Residential Rate Comparison



[11] Nelson deposition, p. 24, l. 20 through p. 25, l. 2.

This empirical comparison does not suggest that data center growth, in and of itself, results in disproportionate increases in rates. If data center load were inherently rate-increasing, one would expect the largest data center markets to exhibit the greatest rate growth. The available data does not support that conclusion.

IV. TRANSMISSION COST ALLOCATION

Q. How does Mr. Nelson propose that transmission-related costs be allocated under the LLCP?

A. Mr. Nelson recommends that DEF allocate all transmission costs built to serve a new large load customer to that customer, including upstream transmission network upgrades that are triggered by the customer. He proposes that such costs be collected up front as a deposit. The portion associated with network upgrades would be refundable over time through credits, while the portion associated with direct-connection facilities would be retained as nonrefundable CIAC.[12]

Q. Do you agree that upstream transmission network upgrades should be fully funded by a single large load customer?

A. No. Upstream transmission network upgrades are fundamentally different from direct interconnection facilities. Transmission network upgrades are planned and constructed to address system conditions such as reliability constraints, thermal overloads, and congestion. Even when triggered by a specific load addition, those facilities become

[12] Nelson Direct at 35:3-13

integrated components of the broader transmission system and provide ongoing benefits to all users in the form of improved reliability, reduced congestion, and enhanced operational flexibility.

Under traditional cost allocation principles, facilities that provide system-wide benefits are recovered on a system-wide basis. Assigning 100 percent of such costs to a single customer would represent a significant departure from established transmission ratemaking practice and would ignore the broader benefits those facilities provide to the grid.

Q. Mr. Nelson analogizes large load customers to generators and references FERC precedent. Is that comparison appropriate?

A. No. Mr. Nelson cites FERC Order No. 2003 and related precedent regarding generator interconnection and direct assignment of network upgrade costs.[13] That comparison is misplaced.

Under FERC Order No. 2003, transmission network upgrade costs initially assigned to interconnecting generators are subject to reimbursement through transmission credits over time. The generator ultimately pays transmission rates like other transmission customers, and the costs of network upgrades are reflected in the transmission revenue requirement recovered from all users of the system.

[13] Nelson Direct at 34:16-23.

Large load customers are not generators seeking to inject power onto the grid. They are retail customers taking service under state jurisdictional tariffs. Applying generator interconnection principles to retail load would conflate two fundamentally different regulatory frameworks and would not reflect how transmission facilities serving load have historically been planned and recovered.

Q. Mr. Nelson recommends that direct interconnection transmission facilities be funded through a non-refundable CIAC. Is that consistent with DEF's existing tariff and the Commission's line extension rule?

A. No. Mr. Nelson recommends that the portion of transmission costs associated with direct-connection facilities be retained by the Company as non-refundable CIAC.[14] That approach is not consistent with DEF's existing tariff framework.

Under Section 3.01 of the Company's tariff, CIAC is determined by netting four years of expected incremental base energy and base demand revenues against the estimated cost of the extension or upgrade. If the four-year expected base revenues equal or exceed the cost, no CIAC is required.[15] Thus, the tariff embeds a four-year revenue offset directly into the calculation of any required CIAC.

Mr. Nelson's recommendation to require non-refundable CIAC for direct-connection transmission facilities would eliminate the revenue offset structure embedded in

[14] Nelson Direct at 35:12-13.
[15] DEF Tariff Section VI, Sheet No 4.030, Part III, 3.01.

Section 3.01 and would therefore represent a departure from DEF's longstanding extension policy rather than an application of it.

V. PEAK DEMAND THRESHOLD

Q. Mr. Nelson recommends lowering the Large Load threshold from 100 MW to 50 MW. Do you agree?

A. No. The 100 MW threshold appropriately targets customers whose size and concentration risk materially differ from other industrial customers. As I explained in my Direct Testimony, a single 100 MW customer represents a step-change in exposure relative to traditional loads and warrants tailored contract protections.[16] Lowering the threshold to 50 MW would sweep in customers that do not present the same system or financial risk profile and would unnecessarily broaden the applicability of enhanced terms.

Q. Do other jurisdictions use a peak demand threshold of 100MW or higher?

A. Yes. Several jurisdictions have adopted thresholds at or above 100 MW or have applied enhanced provisions only to extremely large loads. For example, Wisconsin Electric Power Company proposed a 500 MW "bespoke" structure for very large customers that effectively ringfences costs for those customers. Kentucky Power applies enhanced contractual protections to large loads above 100 MW. The Georgia Public Service Commission recently adopted rules focused on large data center loads with a threshold of 100MW. Xcel Energy in Minnesota likewise applies specific large load provisions

[16] Wishart Direct at 27:8-15.

to customers at or above 100 MW. In addition, Consumers Energy in Michigan defines a large load customer as having 100 MW or more at a single or aggregated site and applies enhanced contractual protections at that level. These examples demonstrate that maintaining a 100 MW threshold is consistent with national practice and reflects the fact that risks materially change at very large load levels.

VI. EARLY TERMINATION FEES

Q. What does Mr. Nelson recommend with respect to early termination fees?

A. Mr. Nelson recommends that the termination fee for a Large Load customer be set equal to the minimum monthly charges for the entire remaining term of the contract. In his view, this approach is necessary to fully protect other customers from stranded cost risk. He further asserts that only a limited number of utilities use termination provisions that differ from this structure.[17]

Q. Is it appropriate to require payment of minimum bills for the full remaining contract term in all cases?

A. No. Exit fees should reasonably reflect the potential financial risk created by an early departure, not operate as a punitive mechanism. The relevant question is the time period over which the utility is reasonably exposed to stranded cost risk. Under DEF's proposal, the termination fee equals 36 months of minimum charges during the earlier portion of the contract and 24 months during the later portion. In addition, the customer must provide two to five years of notice before being able to terminate (and if they do

[17] Nelson Direct at 43:12-18

not provide that notice, the termination fee will include the minimum bills from those years in addition to the 36/24 months of minimum charges). That structure is risk-based and time-sensitive. It recognizes that:

1. The utility's exposure is greatest in the early years when capital investments are being recovered; and
2. Over time, the likelihood of backfilling the capacity increases as the region continues to experience load growth.

A 24- to 36-month window is a reasonable and commercially practical period for DEF to secure a replacement customer to utilize the released capacity. DEF operates in a growing Florida market with continued demand expansion. In that context, a multi-year exit fee provides a meaningful buffer against stranded costs while avoiding over-collection that exceeds the likely duration of financial exposure.

Importantly, exit fees should balance two objectives. The first is protecting existing customers from stranded investment risk and the second is avoiding unnecessarily restrictive terms that could deter economically beneficial load. DEF's proposal strikes that balance.

Q. Did Mr. Nelson accurately characterize utility practice regarding termination fees?

A. No. While Mr. Nelson suggests that most utilities require payment of minimum bills for the entire remaining contract term, that characterization is incomplete. Several utilities use alternative structures that do not automatically require payment of minimum bills through the end of the contract.

Examples include:

- AEP Ohio, which employs a structured termination charge rather than full remaining minimum bills;
- Indiana Michigan Power, which includes defined exit provisions not tied strictly to full-term minimum billing;
- Kentucky Power, which utilizes termination provisions that differ from full remaining minimum obligations;
- Xcel Energy Minnesota, which has adopted alternative approaches to termination exposure; and
- Ameren Missouri, whose tariff provides that the Company will use commercially reasonable efforts to mitigate the amount of the exit fee.

The Ameren provision is particularly notable because it explicitly recognizes that termination exposure should be mitigated where possible. By requiring commercially reasonable efforts to reduce the financial impact, Ameren acknowledges that the true measure of risk is the net stranded cost after mitigation, not the gross amount of remaining minimum bills.

These examples demonstrate that utility practice is not uniform and that full-term minimum billing is not the only reasonable method to protect ratepayers.

Q. What is your conclusion regarding DEF's proposed early termination fees?

A. DEF's 24- to 36-month termination structure reasonably reflects the expected duration of financial exposure and provides meaningful protection against stranded cost risk. It aligns with risk-based principles used in other jurisdictions and appropriately balances ratepayer protection with economic competitiveness. Accordingly, I conclude that DEF's proposed early termination fees are reasonable and should be approved.

VII. MINIMUM MONTHLY BILLING

Q. What is Mr. Nelson's recommendation regarding minimum monthly billing?

A. Mr. Nelson does not oppose the Company's proposed minimum demand charges of 75% to 85%. However, he recommends that the Company also impose a minimum load factor of 60% for purposes of calculating the minimum monthly bill. In support of this recommendation, Mr. Nelson presents illustrative minimum bill calculations in Tables 1 and 2 and cites examples from other recent large load tariffs.[18]

Q. Do Mr. Nelson's Tables 1 and 2 accurately reflect appropriate minimum bill design principle?

A. No. Mr. Nelson's examples materially overstate the role of volumetric energy charges in the minimum bill calculation because they necessarily include fuel and other

[18] Nelson Direct at 47:10-15

volumetric riders in the calculation. By dividing the volumetric charges shown in his tables by the associated MWh volumes, the implied average volumetric charge equals approximately $0.0559 per kWh. That figure is significantly higher than DEF's base energy charge under LLC-1 of approximately $0.0104 per kWh.

The only way to arrive at a volumetric charge of $0.0559 per kWh is to include the fuel cost recovery charge, which is approximately $0.04334 per kWh, along with other volumetric riders. Including fuel recovery in a minimum bill calculation is inconsistent with fundamental cost causation principles. Fuel is a variable cost that is incurred only when energy is actually consumed. If a customer does not take energy, it does not cause fuel to be burned and therefore should not be charged for fuel it did not use. Minimum bills are intended to ensure recovery of fixed or capacity-related costs associated with maintaining service availability, not to guarantee recovery of variable commodity costs that are usage-driven.

If Mr. Nelson had limited his example to the base energy charge of $0.0104 per kWh, his results would have demonstrated that energy charges are approximately 75% of the demand charges, rather than the roughly 350% relationship depicted in his Table 2. In other words, the dramatic imbalance shown in his illustration is driven by the improper inclusion of fuel and other volumetric riders. Because that inclusion incorporates fuel and clause-based charges that are not relevant to fixed cost recovery in a termination context, it overstates the magnitude of volumetric recovery and renders Mr. Nelson's minimum bill example unreliable.

Q. Does Mr. Nelson accurately characterize recent Virginia large load tariffs as requiring a minimum billing volume?

A. No. Mr. Nelson states that Appalachian and Dominion recently proposed large load tariffs that include a minimum energy charge equal to 60% of contracted demand multiplied by monthly billing hours. [19] With respect to Dominion, that characterization is inaccurate. Dominion's GS-5 customer class includes a minimum 75% load factor requirement as a condition of eligibility into the GS-5 rate class. That provision defines which customers qualify for service under the tariff; it is not a minimum bill requirement that mandates payment for energy regardless of actual consumption. The distinction is significant. A class eligibility criterion does not require a customer to pay for unconsumed energy. By contrast, a minimum billing volume requirement would compel payment for energy whether or not it was taken. Dominion's proposal contains the former, not the latter.

Q. Is there evidence that other utilities impose a minimum load factor requirement as part of minimum bill calculations?

A. The record does not demonstrate that other utilities impose a minimum load factor requirement for purposes of determining minimum monthly bills. Moreover, Mr. Nelson's apparent inclusion of the fuel rider in his minimum bill calculation is out of step with established rate design principles. Variable costs such as fuel are recovered through volumetric charges precisely because they are caused by consumption.

[19] Nelson Direct at 47:4-8

Requiring a customer to pay fuel charges for energy that it did not consume would be inconsistent with cost causation, would risk over-recovery of variable costs, and would represent an unusually restrictive and extreme condition for inclusion in DEF's LLC proposal.

For these reasons, Mr. Nelson's recommendation to impose a 60% minimum load factor for minimum bill purposes is not supported by sound rate design principles and should be rejected.

VIII. SECURITY COLLATERAL

Q. Please summarize Mr. Nelson's recommendation regarding security collateral.

A. Mr. Nelson recommends that the LLCP be amended to require security collateral equal to twenty-four months of minimum bills, based on a customer's planned peak post ramp period demand.[20] In his view, a two year security requirement calculated on that basis is necessary to protect other customers from the financial risk associated with large load customers that may reduce or terminate service.[21] Mr. Nelson's proposal would require the full twenty four months of minimum bills without reference to credit quality or other mitigating factors.

Q. Is Mr. Nelson's proposal consistent with recent large load tariffs adopted in other jurisdictions?

[20] Nelson Direct at 43:1–6.
[21] Id.

A. No. While several utilities have adopted a nominal collateral requirement equal to twenty-four months of minimum bills, those same utilities have incorporated substantial credit-based reductions that materially lower the actual security required for creditworthy customers. Mr. Nelson's recommendation does not reflect those important features.

For example, Ameren Missouri's Large Load Customer Service tariff establishes a base collateral requirement equal to two years of Minimum Monthly Bills.[22] However, Ameren provides for exemptions of up to sixty percent of that amount for customers and guarantors that satisfy specified credit rating and liquidity standards. [23] As a result, a highly rated customer may be required to post collateral equivalent to only forty percent of the nominal twenty-four-month requirement, which equates to approximately 9.6 months of minimum bills. In addition, Ameren provides further graduated reductions for customers with lower, but still investment grade, credit ratings. Id.

Evergy Missouri has adopted a materially similar structure. Its Schedule LLPS requires collateral equal to two years of Minimum Monthly Bills.[24] At the same time, Evergy allows exemptions of up to sixty percent of that requirement for customers that meet defined credit standards.[25] Thus, like Ameren, Evergy's effective collateral

[22] Amended Non-Unanimous Global Stipulation and Agreement. Before the Public Service Commission of Missouri, Proceeding No. ET-2025-0184 at ¶ 23 https://efis.psc.mo.gov/Document/Display/859499 at
[23] Id. at ¶ 24-27
[24] Non-Unanimous Global Stipulation and Agreement. Before the Public Service Commission of Missouri, Proceeding No. EO-2025-0154 at ¶ 21 https://efis.psc.mo.gov/Document/Display/857073
[25] Id. at ¶ 22-25

requirement for strong credits may be substantially less than twenty-four months of minimum bills.

Indiana Michigan Power likewise incorporates significant credit-based flexibility. While its tariff includes a two-year baseline security requirement, it provides for full exemption in certain circumstances for highly rated entities and a fifty percent reduction for other qualifying customers,[26] thereby reducing the effective collateral requirement well below twenty-four months for customers that demonstrate strong financial capacity.

Q. What is your conclusion regarding Mr. Nelson's security collateral recommendation?

A. Mr. Nelson's recommendation would impose a rigid requirement equal to twenty-four months of minimum bills without meaningful credit-based adjustment. That approach is more restrictive than the frameworks adopted by other utilities serving large load customers. Recent large load tariffs recognize that the financial risk posed by a customer depends not only on the size of the load, but also on the customer's creditworthiness and liquidity. By incorporating tiered reductions tied to objective credit standards, those tariffs balance protection for other customers with commercially reasonable terms for creditworthy large load customers.

[26] Unopposed Settlement Agreement and Unopposed Motion for Acceptance Out of Time Filing. Indiana Utility Regulatory Commission, Cause No. 46097 at ¶ 5

In contrast, a mandatory twenty-four-month requirement in all circumstances would overstate the risk associated with investment grade customers and would be inconsistent with emerging industry practice. DEF's proposal, which provides for flexibility in determining appropriate collateral based on the specific customer and circumstances, appropriately reflects the need to protect existing customers while remaining competitive in attracting large, creditworthy loads.

IX. LOAD RAMP PERIOD

Q. Please describe DEF's proposal regarding the load ramp period under the Large Load Customer Policy.

A. The LLCP allows for a negotiated ramp period during which the customer's load increases to its full contracted demand level. During the ramp period, the customer remains subject to minimum billing demand requirements, but the Company retains discretion to negotiate the duration and structure of the ramp as part of the Large Load Customer Agreement LLCA.[27] The proposal contemplates that large customers may phase in capacity in tranches as facilities are constructed and commissioned, rather than reaching full contracted demand immediately upon commencement of service.

Q. What concerns does Mr. Nelson raise regarding DEF's proposed load ramp provisions?

A. Mr. Nelson argues that the proposed ramp provisions provide too much flexibility and insufficient protection for existing customers. He expresses concern that allowing

[27] Duke Energy Florida, Large Load Customer Policy, as filed in Docket No. 20250113-EI.

extended or loosely defined ramp periods could permit a customer to reserve significant system capacity without fully paying for it during the early years of the contract. In his view, insufficiently constrained ramp provisions increase the risk that incremental generation and transmission resources will be constructed in advance of full revenue recovery, thereby exposing other customers to potential cost shifting if the projected load growth does not materialize as expected.[28]

Mr. Nelson therefore recommends that the Commission impose clearer limits on ramp duration and structure to ensure that large load customers pay for reserved capacity in a manner that appropriately reflects the costs they cause to be incurred.

Q. Mr. Nelson recommends modifying DEF's proposed load ramp provisions. Is DEF's proposal consistent with how other utilities structure large load tariffs?

A. Yes. DEF's proposed load ramp framework is consistent with, and in some respects more structured than, the approaches adopted in other jurisdictions. For example, Evergy's large load settlement does not establish a fixed, staged ramp schedule with prescribed annual percentages, but instead relies on minimum billing demand requirements and contract terms to manage risk. Similarly, Florida Power & Light's large load tariff contemplates negotiated implementation timelines rather than a rigid Commission-prescribed ramp formula. Kentucky Power's recently approved 150 MW Industrial General Service tariff likewise does not include a defined load ramp

[28] Nelson Direct at 51.

schedule, but instead relies on long-term contracts, minimum billing demand provisions, and financial safeguards to address underperformance risk.

In comparison, DEF's proposed ramp period provides a clear, structured transition to full contract demand while maintaining meaningful minimum billing protections. It appropriately balances flexibility during construction and commissioning with the need to protect existing customers from stranded capacity risk.

X. FLEXIBLE INTERCONNECTION

Q. Mr. Nelson recommends that DEF consider flexible or non-firm interconnection arrangements for large load customers. Please summarize his position.

A. Mr. Nelson suggests that DEF should consider allowing large customers to interconnect on a flexible or non-firm basis, under which some portion of the customer's load could be curtailed during system constraints. He argues that such arrangements could reduce the need for new generation or transmission investment by limiting demand during peak or constrained periods.

Q. Is flexible interconnection a widely adopted practice for large data centers?

A. No. While flexible interconnection has been discussed in academic and policy literature, it is not a widely adopted commercial practice for hyperscale data centers. The Duke University study cited by Mr. Nelson, *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in U.S. Power Systems*, acknowledges that most large commercial and industrial customers, including data centers, require highly reliable firm service. The study explains that interruptible or flexible service would require new contractual frameworks, monitoring tools, and operational arrangements, and that such approaches are emerging concepts rather than established industry standards.

Similarly, the Virginia JLARC report evaluating the impact of data center growth on electric rates does not identify flexible interconnection as a common or prevailing solution. The JLARC report explains that data centers typically take firm service and that utilities plan generation and transmission resources accordingly. The report discusses demand flexibility conceptually but does not cite widespread use of non-firm interconnection arrangements for large data centers in Virginia.

Q. Is there evidence that major utilities serving significant data center load have adopted flexible interconnection as a standard offering?

A. No. Dominion Energy Virginia, which serves the largest concentration of data centers in the United States, did not propose a flexible or non-firm interconnection option when it developed its GS-5 rate class for very large customers. Instead, Dominion retained a firm service structure and addressed cost recovery and risk mitigation through rate design, minimum demand provisions, and contract terms. The absence of a flexible interconnection structure in Dominion's GS-5 proposal is notable given the scale of data center development in its service territory.

Q. What is your conclusion regarding Mr. Nelson's recommendation?

A. Mr. Nelson's proposal relies on theoretical or emerging concepts rather than demonstrated industry practice. Both the Duke University study and the JLARC report acknowledge that data centers generally require firm service and that flexible interconnection would require significant operational and contractual evolution. Moreover, major utilities with extensive data center experience, such as Dominion Energy Virginia, have not adopted flexible interconnection as a standard tariff offering. Notably, Mr. Nelson admitted in his deposition that no Commission has mandated flexible connections for large load customers.[29] Accordingly, Mr. Nelson's recommendation does not reflect established practice and does not provide a basis to modify DEF's proposed LLCP.

Q. Does that conclude your testimony?

A. Yes.

[29] Nelson deposition, p. 17, l. 7-10.