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May 15, 2024

Ms. A. Shonta Dunston
Chief Clerk
NC Utilities Commission
430 N. Salisbury Street
Room 5063
Raleigh, NC 27603

Via Electronic Submission

**Re: In the Matter of**
**Petition to Revise Commission Rule R8-63 and R8-64**
**NCUC Docket E-100 Sub 176**
***SunEnergy1 LLC's Comments in Compliance with Commission's Order dated April 1, 2024, and Subsequent Order dated May 1, 2024***

Dear Ms. Dunston:

On April 29, 2024, SunEnergy1, LLC ("SunEnergy") filed a Petition to Intervene and Motion to Extend the Deadline for Filing Comments. SunEnergy's Petition to Intervene was granted by the Commission on April 30, 2024, and the Motion for an Extension of Time to File Comments was later granted by the Commission on May 1, 2024, until May 15, 2024, with Reply Comments due on or before May 31, 2024.

In accordance therewith, SunEnergy submits it Comments in the above referenced matter and docket.

If you have any questions concerning this filing, please let me know. Thank you for your assistance.

Sincerely,

/s/ Benjamin L. Snowden

Benjamin L. Snowden

pbb

Enclosure

Copy to: Parties and Counsel of Record
NC Public Staff

**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-100, SUB 176

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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| In the Matter of<br><br>Petition to Revise Commission Rules R8-63 and R8-64 | )<br>)<br>)<br>)<br>)<br>)<br>) | INITIAL COMMENTS OF SUNENERGY1 ON PROPOSED REVISIONS TO RULE R8-63 |

Pursuant to the Order Requesting Comments ("April 1 Order") issued in this docket on April 1, 2024, Intervenor SunEnergy1 LLC ("SE1"), by and through counsel, provides the following comments regarding the proposed revisions to Rule R8-63 attached as Attachment A to the April 1 Order. SE1 has no direct comments on the proposed changes to Rule R8-64 included as Attachment B to the April 1 Order, although many of the issues raised in SE1's comments would apply to the proposed R8-64 revisions as well.

## I. INTRODUCTION

As a developer of merchant renewable energy project, SunEnergy1 appreciates the opportunity to provide comments on the Commission's proposed revisions to the merchant CPCN rule. The Public Staff and the Commission have proposed many helpful and clarifying changes to the rules. SE1 understands and acknowledges the concerns about affected system upgrades that animate many of the proposed revisions, and SE1 agrees with the need for applicants to produce relevant information about upgrade costs as it becomes available. However, SE1 is concerned that, depending on how the Commission applies these rules – and in particular, if the Commission demands total certainty as to affected system costs before it will take action on a CPCN application – the revised rules may effectively paralyze merchant project development in the North Carolina portion of PJM.

SunEnergy1 is a family-owned business headquartered in North Carolina. It was started in 2009 with the goal of making renewable energy more accessible and sustainable. Since that time, SE1 has grown to become a leading U.S. solar developer, owner, and operator of utility-scale solar projects, with close to 1 gigawatts of installed solar capacity. SunEnergy1 has pioneered large-scale solar power on the East Coast for more than a decade, and has developed numerous record-breaking solar projects in the region. SunEnergy1 has 300 employees in North Carolina and has plans to continue developing clean energy projects in the state, as well as elsewhere in the PJM territory.

Like all developers of independent energy projects, SunEnergy1 must make very large investments of time and money before realizing any project revenues. Although development carries many inherent risks that a developer can address, regulatory risk is particularly hard to deal with because it can prevent a developer from transacting a project, making significant cash outlays, or from obtaining third-party financing for major financial commitments that are required to proceed through the interconnection process. Even delays in the ability to commence construction (that may be occasioned by the CPCN process) equate to costly delays in realizing a return on the developer's investment.

Fortunately this Commission has long recognized the need for regulatory certainty in the implementation of sound regulatory policy.[1] SunEnergy1 is hopeful that the Commission, as it implements its revised CPCN rules, will take into account all parties' need for regulatory certainty even as it fulfils its role of protecting North Carolina ratepayers.

[1] *See, e.g.*, *In the Matter of Biennial Determination of Avoided Cost Rates for Elec. Util. Purchases from Qualifying Facilities - 2014*, Docket No. No. E-100, Sub 140 (Dec. 31, 2014) (maintaining status quo of certain terms in standard contracts for qualified facilities because, among other reasons, changes would "introduce regulatory uncertainty" and stating, "[i]n balancing the costs, benefits and risks to all parties and customers, the Commission recognizes that regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy."); *In the Matter of Biennial Determination of Avoided Cost Rates for Elec. Util. Purchases from Qualifying Facilities - 2018,* Docket No. E-100, Sub 158 (Apr. 15, 2020) (maintaining status quo of certain terms in a stipulation between electric utilities and hydroelectric generators because, in part, of "prudential considerations and those of regulatory certainly"); *In the Matter of Rulemaking Proceeding to Implement Session L. 2007-397*, Docket No. E-100, Sub 113 (Dec. 16, 2019) (rejecting intervenor's request for an evidentiary hearing and maintaining status quo relative to deciding the merits based on reports and verified filings because of "considerations such as regulatory certainty and efficient implementation of the [renewable energy portfolio standard] requirements").

## II. Comments on Proposed Rule R8-63

### A. Treatment of Affected System Upgrade Costs

The proposed revisions to Rule R8-63 require that a CPCN applicant include, in its application:

> An affected system study from any neighboring utilities detailing any affected system upgrades and associated costs for any facility that that has required affected system upgrades listed in a feasibility study, system impact study, or facilities study. If an affected system study has not been completed, provide a statement that the facility has been considered for affected system impacts and it has been determined that there are not any such impacts or required upgrades.

SE1 understands that the potential of a proposed facility to trigger affected system upgrades is relevant to the whether construction of the facility is consistent with the public convenience and necessity, and that the Commission has a legitimate interest in protecting North Carolina ratepayers from the imposition of unreasonable upgrade costs by merchant facilities. However, it is unreasonable to require an applicant to delay filing an application until an affected system study has been prepared, or until the applicant has "a statement that the facility has been considered for affected system impacts and it has been determined that there are not any such impacts or required upgrades." And while it is unclear how the Commission intends to apply the proposed rule, it is both untenable and unnecessary to delay action on a CPCN until there is absolute certainty about the affected system costs that may be required.

### 1. Financial commitments in the project development cycle

The development of any solar facility requires significant financial commitments at several stages of the process. In addition to the costs of securing site control, obtaining local permitting, conducting environmental and other studies of the proposed site, and designing a proposed facility, just entering the PJM interconnection process requires hundreds of thousands of dollars in study deposits. Developers understand that for any given project these investments are at risk, whether the project ultimately can be built or not.

However, going through the PJM interconnection process requires even larger financial commitments that most developers cannot prudently commit to without having any certainty that the project can obtain a CPCN from this Commission. Under PJM's recently reformed interconnection process, required "readiness deposits" increase at each stage of the study process. Within approximately 100 days after completion of the second phase of PJM's cluster-based system impact study, an Interconnection Customer must execute an interconnection agreement and post nonrefundable financial security sufficient to cover the cost of upgrades allocated to the project, or be withdrawn from the queue.[2] These costs can reach tens of millions of dollars. Unless its upgrade costs are

[2] The readiness requirements for PJM's interconnection process, which was revised substantially in 2022, are summarized in PJM's filing with FERC seeking approval of its revised OATT (which approval was later granted). See PJM Interconnection, L.L.C., Docket No. ER22-2110, Tariff Revisions for Interconnection Process Reform, Request for Commission Action by October 3, 2022, and Request for 30-Day Comment Period (filed June 14, 2022), available at https://pjm.com/directory/etariff/FercDockets/6726/20220614-er22-2110-000.pdf.

minimal, a developer cannot obtain cash or a letter of credit to cover these obligations without knowing whether the project can even be constructed.[3]

Unfortunately, under the FERC process established in Order No. 2023 (and in Duke's compliance filing), an affected system study may not be prepared until well after the interconnection customer must make those commitments. Under Duke's compliance filing for Order No. 2023,[4] Duke's duties as a potential affected system are triggered when it receives notice that its system may be impacted by an interconnection request to a neighboring or other utility's system.[5] Within 20 business days thereof, Duke must respond in writing whether it intends to conduct an affected system study. If it does, Duke has 15 business days to provide a good faith estimate of the cost and the schedule to complete the affected system study and 10 business days thereafter to deliver an affected system study agreement to the interconnection customer.[6] Once the interconnection customer receives the affected system study agreement, it has 10 business days to execute the agreement and provide the study deposit.[7] Duke has 150 calendar

[3] Although Section 11.2.1 of FERC's pro forma LGIP allows an Interconnection Customer to request a delay in execution of its Interconnection Agreement until 30 days after receipt of an Affected System Study report, the Transmission Provider may refuse to grant that extension if it determines that such delay "would cause a material impact on the cost or timing of an equal- or lower-queued interconnection customer[.]"

[4] Both PJM and Duke have made Order No. 2023 compliance filings with FERC, both of which deviate from FERC's pro forma LGIP and LGIA, but neither has been accepted by FERC at this time.

[5] Proposed LGIP § 9.2.

[6] Id. § 9.4.

[7] *Id.* § 9.5.

days to complete the study and deliver a report.[8] Duke must provide an affected system facilities construction agreement within 30 calendar days of providing the report, and, within 10 business days thereof, the interconnection customer must execute the agreement.[9] Under Duke's *pro forma* Affected System Facilities Construction Agreement (the successor to Duke's current Affected System Operating Agreement), the interconnection customer(s) must provide security for the payment of network upgrades at the earlier of 30 calendar days before interconnection customer's first payment due thereunder, or the first date specified thereunder for Duke to order equipment.[10] Again, most developers (including SE1) will be unable to obtain the required financial security without knowing that the Commission is likely to approve their CPCN.

Although FERC Order No. 2023 promises to provide much-needed clarity in the affected system study process, those reforms will not be helpful to merchant projects in North Carolina if this Commission declines to consider CPCN applications under Rule 63 until affected system upgrade costs have been fully developed. Even if the Commission is willing (as it has been in the past) to issue CPCNs for merchant projects that trigger only modest affected system upgrades, a delay in obtaining a CPCN until after affected system costs are fully developed is likely to render developers unable to meet the multi-million dollar financial commitments that occur earlier in the

[8] Id. § 9.7.
[9] Id. § 9.10.
[10] Proposed ASCA § 4.1.

interconnection process. This will make it prohibitively difficult to develop merchant solar projects in North Carolina.

In addition to the financial commitments required in the interconnection process, it is standard for Power Purchase Agreements (PPAs) with offtakers in PJM to include multi-million dollar performance guarantees on the part of the seller, which are forfeit if the project cannot deliver.[11] PPAs may also include significant liquidated damages for delays in achieving COD. Consequently, a rational developer cannot sign a PPA until it has some certainty that the facility can be constructed, and when.

**2. North Carolina is not on the verge of a "Friesian situation" with respect to affected system upgrades.**

SE1 understands that the Commission's current concerns about affected system upgrades triggered by merchant plants in PJM is driven, in large measure, by the situation that gave rise to the Friesian Order,[12] and that the Commission is concerned about the possibility that North Carolina ratepayers will be forced to subsidize a large affected system upgrade (or group of upgrades) triggered by a PJM facility, "given the increase in the number of applications for CPCNs by merchant generators and pending interconnection requests by merchant generators."

[11] The standard power purchase agreements approved by the Commission for Duke Energy's solar procurements include similar performance guarantees

[12] Order Denying Application for a Certificate of Public Convenience and Necessity for a Merchant Generating Facility in Docket No. EMP-105, Sub 0 (Friesian Order)

However, SE1 submits that North Carolina is not on the verge of a "Friesian situation," and that the Commission can protect ratepayers from this eventuality without shutting down merchant plant development in North Carolina entirely.

As noted in the Friesian order, the large upgrades triggered by the Friesian project were driven by very rapid solar development in the area where the Friesian project was to be built, leading to severe congestion in that area of Duke's system. That part of the grid was known to be constrained for years prior to Friesian's application coming before the Commission. And indeed, the Commission based its decision to deny Friesian's CPCN in part on its conclusion that "the placement of additional uncontrolled solar generating capacity in a region of the DEP system that currently contains significant existing solar generation may increase and exacerbate system operational issues already being faced by DEP's system operators[.]" Friesian Order at 6.

That is not the situation here. Although there is significant solar development in Dominion's North Carolina service territory, PJM and Duke's transmission grids have yet to experience the level of congestion that Duke experienced long before Friesian came before the Commission. In fact, the aggregate cost of affected system upgrades on DEP's system triggered by PJM projects to date is relatively low. In comments on the FERC proposal that ultimately resulted in Order No. 2023, the Commission and Public Staff's engineers identified approximately $126 million in "known affected system upgrade costs" triggered by PJM projects in 2022, and characterized these upgrades as "the tip the iceberg" based on the size of PJM's interconnection queue.[13]

The situation has changed significantly since then. At this time, DEP has conducted (and revised) affected system studies on PJM clusters through AE1, and has identified only two upgrades required to address the impacts of these projects: the Rocky Mount-Battleboro 115 kV uprate, and the uprate of the Everetts-Greenville 230 kV line. The total estimated cost of these projects is less than $17 million.[14] These changes were driven in large measures by withdrawals from PJM's interconnection queue, presumably driven by PJM's queue reform efforts (which were intended to drive speculative projects out of the queue). PJM has now initiated its transitional cluster study process, the final results of which will likely be available in 2025. The fact that Duke and Dominion are now required to file quarterly reports on affected system studies, and to make those studies (and all revisions) public means that there is much greater transparency and visibility about emerging issues on Duke's system.

Another important distinction between Friesian and PJM merchant plants is that whereas Friesian (which planned to interconnect under Duke's OATT) would have

[13] Joint Comments of The North Carolina Utilities Commission and the North Carolina Utilities Commission Public Staff, FERC Docket No. RM22-14-000 (Oct. 13, 2022) ("NCUC Comments") at 22.
[14] Based on recent update filings in EMP dockets, the estimated cost of the Rocky Mount-Battleboro project is now $16.5 million, down from an estimate of approximate $30 million in the Affected System Operating Agreement for that project. Duke has concluded that the Everetts-Greenville upgrade is required for reliability purposes, and has estimated in incremental cost of $150,000 for enhancements to that upgrade to accommodate merchant generation.

received reimbursement from ratepayers for 100% of its upgrade costs on Duke's system, merchant plants in PJM pay for their own upgrades, without any reimbursement. Only where there is an affected system upgrade may an interconnection customer receive any reimbursement for upgrade costs. Moreover, changes to the affected system process under Order No. 2023 (discussed above) will now allow affected system upgrade costs to be allocated among all the projects in a single cluster that contribute to the upgrade – unlike Friesian, which under the then-existing serial queue process was allocated the entire cost of the upgrades required for that region of Duke's system.

The point of this is not that a Friesian situation could *never* arise with respect to affected system upgrades, but that the Commission will most likely be on notice well before it does, and be able to act accordingly. The Commission therefore does not need to take the most conservative approach possible to affected system upgrades, at the cost of potentially shutting down merchant plant development in North Carolina.

**3. The Commission should provide clear and reasonable guidance on the use of LCOT calculations in CPCN applications.**

A significant source of uncertainty regarding CPCN proceedings is how the Commission actually weighs LCOT values in its decision-making. At this time, the only definitive statements made by the Commission regarding LCOT are that: (1) the use of LCOT provides a benchmark as to the reasonableness of the transmission network upgrade cost associated with interconnecting a proposed new generating facility; (2) the LCOT values (ranging from $1.56 to $3.22/MWh) set forth in the 2019 LBNL study relied on in the Friesian Order and subsequent orders are useful comparators; and (3) the $62.94/MWh LCOT value attributed to the Friesian project was unreasonable. Although it would be inconsistent with the flexible nature of CPCN decisions to codify a specific LCOT value that is permissible across the board, *some* guidance from the Commission would be extremely valuable to merchant developers, and might mitigate some of the uncertainty caused by delaying CPCN decisions. If, for example, the Commission were to establish LCOT values that would be presumptively reasonable in the current environment (five years after the LBNL study was issued), that might provide useful guidance to developers on whether their projects might be approved after full consideration by the Commission.

With respect to LCOT values, SE1 also notes the Commission has recently directed CPCN applicants to provide LCOT calculations for affected system upgrades assuming only the output of their individual projects. While this information may be of interest to the Commission, SE1 submits that where multiple projects have been allocated affected system upgrade costs -- and have made financial commitments to pay those costs up front – it is unreasonable to discount the output of those facilities in considering the LCOT of an individual project. Accordingly, SE1 proposes that the revised rule specify that an applicant be permitted to provide alternative LCOT calculations based on the allocated cost of upgrades.

4. **Requiring CPCN Applicants, not utilities, to quantify the benefits of individuals upgrades is unreasonable.**

Proposed R8-63(b)(5)(vii) would require an applicant to provide, in its initial CPCN application, "A detailed description, including quantification, of any benefits to be received by ratepayers from any transmission upgrades, including affected system upgrades, the need for which is caused by the proposed facility, with specific reference to each upgrade identified in the relevant interconnection study."

SE1 understands that the costs and benefits of a proposed generator are important considerations in the CPCN process, and acknowledges the Commission's legitimate concern about the possibility that North Carolina retail ratepayers may be required to partially fund Affected System Upgrades on DEP's system that may benefit generators that are not constructed to serve North Carolina retail customers. SE1 also agrees that a systematic investigation of the benefits of these upgrades would assist the Commission. However, it is unreasonable to demand that *CPCN applicants* quantify the benefits *to ratepayers* of each of the upgrades identified interconnection studies for the proposed facility. Utilities alone have this information or the ability to develop it.

The only information generally available to a project developer about the upgrades required for the proposed facility is contained in the interconnection studies produced by the utility. The utilities' tariffs do not require, and utilities do not provide, any information about the benefits of the required upgrades beyond identifying other projects in the same interconnection cluster that may also contribute to the need for the upgrade.

Detailed information about the elements of the grid to be updated – such as the age or condition of existing infrastructure – is generally not available to the public. And while a CPCN applicant may request that utility voluntarily provide information relating to the benefits of an upgrade, there is no requirement that the utility provide that information (or generate it, if it does not already exist).

Although this Commission has taken the position that there DEP's retail customers "will realize no benefit whatever, direct or indirect, from the transmission investments DEP is required to make to accommodate that new generation and its interconnection to the DENC system,"[15] SE1 notes that Duke appears to be actively investigating the potential benefits of building more robust connections to PJM. In its 2022 Carbon Plan Order, the Commission "urge[d] Duke to explore all possible efficiencies and to be vigilant in its participation in SERTP and in its coordination with PJM to assure a least cost path to achieve the carbon dioxide emissions reduction requirements while maintaining and improving reliability."[16] As reported in its 2024 Carbon Plan, Duke has initiated study of a 1000 MW transfer across the PJM- Duke seam.[17] Presumably this study is indicative that there are at least potential benefits of more robust interties between the two systems.

15 NCUC Comments at 14.
16 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100 Sub 179 (Dec. 30, 2022), at 121
17 Carbon Plan Appx L p. 17.

Based on past studies, it is likely that significant improvements to both DEP's and PJM's systems would be required to accommodate this transfer.[18] It is worth noting that while merchant plants may be triggering some upgrades on DEP's system that they are receiving reimbursement for, they are at the same time making much more significant upgrades to the PJM system *at their expense*. If these merchant plants were to disappear, Duke ratepayers would likely be required to fund the entirety of any system improvements required for larger transfers of firm power between Duke and PJM.

The purpose of these examples is not to prove definitively that affected system upgrades are beneficial to DEP ratepayers—it is to demonstrate that the issue of benefits is complex, far-reaching, and not appropriate for resolution on an upgrade-by-upgrade basis in CPCN dockets, where the most important parties (i.e. utilities) are not parties.

Accordingly, SE1 submits that this requirement be stricken from the proposed rule. If the Commission is unwilling to remove that requirement, then fairness dictates that the relevant utilit(ies) be made parties to the docket (assuming the Commission has jurisdiction over them).

**B. Other Aspects of Proposed Rule R8-63**

In addition to the issues discussed above, SE1 has the following comments regarding other elements of the proposed rule. SE1's proposed changes to the

[18] In the initial 2022 proposed Carbon Plan, it was estimated that significant system reinforcement projects are needed on both the PJM and DEP transmission systems to enable such import capacity with initial cost estimates starting at approximately $700 million. (2024 Carbon Plan, Appx. L at 34-35).

Commission's proposed revisions are included in **Attachment A** (as redlines to the Commission's blackline edits).

| Section (R-63) | Proposed Change | Comment / Revision |
|---|---|---|
| (b)(2)(iv) | Requires filing of any "application" for EWG or eligible facility status under PUHCA | - An EWG filing is technically a "certification" (or self-certification), not an "application."<br>- This requirement should be moved to Exhibit 4, which requires the filing of other permits.<br><br>**Proposal: Revise accordingly** |
| (b)(3) | Exhibit 3 to the application requires the applicant to describe the need for the facility, including information regarding offtake and REC sales. | Information about offtake and REC purchases will not be available when a CPCN is applied for. Should specify "if available."<br><br>**Proposal: Revise as indicated.** |
| (b)(5) | Increases disclosures relating to construction and other Adds a requirement that the application provide, Requires "A detailed description, including quantification, of any benefits to be received by ratepayers from any transmission upgrades, including affected system upgrades, the need for which is caused by the proposed facility, with specific reference to each upgrade identified in the relevant interconnection study." | **See general comments on Affected System / IX costs.**<br><br>**In addition:**<br>- A Feasibility study is optional and may not be available.<br>- An applicant has no control over what's in the facilities study. Facilities studies *usually* contain cost estimates for interconnection facilities and upgrades, but (a) PJM facilities studies don't always contain interconnection facilities costs because the IC can self-build; and (b) Costs aren't "final" until they're in the interconnection agreement (which should be filed along with studies). |
| (b)(6) | • Adds the following requirements: a description of involvement of any regulated utility; a statement from the electric utility to which the applicants plans to sell electricity setting forth an assessment of purchased power on the utility's capacity, reserves, generation mix | Many of these requirements do not fit with merchant plant offtake.<br>- 6(iii) – merchant plants don't generally sell to regulated utilities, so this would be inapplicable. |

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| | and capacity expansion; if no utility offtake and/or no offtake agreement, a discussion on how the "output conforms to or varies from the long-range resource plan of a potential utility purchaser;" if the purchaser is subject to a statutory or regulatory mandate, explain how the facility enables compliance and provide supporting contracts; provide PPAs and other contracts for REC compensation | - 6(iv) states that "If the applicant does not plan to sell to an electric utility or does not yet have a definite off-taker, provide a discussion of how the facility's output conforms to or varies from the long-range resource plan of a potential utility purchaser of the power." SE1 seeks clarification from the Commission on this requirement. PJM has many utilities that purchase power from PJM's markets (and not necessarily via PPAs); furthermore, it is in the nature of an interstate market like PJM that utilities are not the only purchasers. So it is unclear how an Applicant could answer this question. |
| (e)(3) | • Changes the Rule so that the certificate expires if construction does not begin in three years<br>• Adds requirements that the certificate holder must update the commission on construction progress prior to the certificate's expiration and failure to do so may result in revocation of certificate<br>• Adds provision that the certificate can be renewed based on a new application (presumably in the same docket) but new application must be filed no later than 90 days prior to the expiration and specifying that amended and/or transferred certificates do not alter the times | - **SE1 appreciates the Commission's efforts to clarify the renewal process for CPCN.**<br>- **Seek clarification on Commission's intended procedures upon receipt of an application.**<br>- **Clarify that the new CPCN should "relate back" to the original, in case the certificate has a legal duty to maintain a certificate without lapse. (May be more important for R8-64)** |
| (e)(4) | • Adds requirement that any changes to information responsive to the exhibits above must be filed by a certificate holder and the Commission will order such proceedings as necessary to address the proposed plans or revisions. | Notice should be required for "significant" changes, just like in R8-64. For example, a change in the list of applicant's other projects in SERC (as required under R8-63(b)(1)(iv)) should not require notice to the Commission. In addition, it would be helpful to include in R8-63 an illustrative list of changes that do or do not require amends, just as in R8-64(d)(4). |

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|---|---|---|
| | | **Proposal:**<br>- **Add language proposed for R8-64 regarding changes that do / don't trigger an amendment** |
| (f) | • Changes the Rule so that the certificate holders must submit annual progress reports and revisions in costs estimates (including upgrades and affected systems) until construction of the facility is complete<br>• Adds requirements that upgrade costs estimated by the interconnecting utility or an affected system that are revised after a certificate is issued must be filed no later than 30 days after issued by the utility | This is all fine but it does not address what happens if updated interconnection studies are issued while an application is pending. For clarity the rule should specify.<br><br>**Proposal:**<br>- **Clarify that an applicant with a pending application should file updated study costs and LCOT figures within 30 days of receipt.** |

Respectfully submitted this the 15th day of May, 2024.

**FOX ROTHSCHILD LLP**

Benjamin L. Snowden

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**CERTIFICATE OF SERVICE**

I hereby certify that all persons on the Commission's docket service list have been served true and accurate copies of the foregoing Petition to Intervene by hand delivery, first class mail deposited in the U. S. mail, postage pre-paid, or by e-mail transmission with the party's consent.

This the 15th day of May, 2024.

/s/ Benjamin L. Snowden

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# Exhibit A

**Rule R8-63. APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR MERCHANT PLANT; PROGRESS REPORTS**

(a) Scope of Rule.

(1) This rule applies to an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) by any person seeking to construct a merchant plant in North Carolina.

(2) For purposes of this rule, the term "merchant plant" means an electric generating facility, other than one that qualifies for and seeks the benefits of 16 U.S.C.A. 824a-3 or G.S. 62-156, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility pursuant to G.S. 62-133.

(3) Persons filing under this rule are not subject to the requirements of Rule R8-61 or R8-64.

(b) Application. The application shall contain the exhibits listed below, which shall contain the information hereinafter required, with each exhibit and item labeled as set out below. Any additional information may be included at the end of the application.

(1) Exhibit 1 shall contain ~~the following information about the applicant~~:

(i) The full and correct name, business address, business telephone number and electronic mailing address of the facility owner; ~~applicant;~~

~~(ii) A description of the applicant, including the identities of its principal participant(s)~~ and ~~officers, and the name and business address of a person authorized to act as corporate agent or to whom correspondence should be directed;~~

(ii) A statement of whether the facility owner is an individual, a partnership, or a corporation and, if a partnership, the name and business address of each general partner and, if a corporation, the state and date of incorporation and the name, business address, business telephone number, and electronic mailing address of an individual duly authorized to act as corporate agent for the purpose of the application and, if a foreign corporation, whether domesticated in North Carolina; and

(iii) The full and correct name of the site owner and, if the site owner is other than the applicant, the applicant's interest in the site; and

~~A copy of the applicant's most recent annual report to stockholders, which may~~ be ~~attached as an exhibit, or, if the applicant is not publicly traded, its most recent balance sheet and income statement. 1~~

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~~If the applicant is a newly formed entity with little history, this~~ information should be provided for its parent company, equity ~~partner, and/or the other participant(s) in the project; and~~

(iv) Information about generating facilities in the Southeastern Electric Reliability Council region which the applicant or an affiliate has any ownership interest in and/or the ability to control through leases, contracts, options, and/or other arrangements and information about certificates that have been granted for any such facilities not yet constructed.

(2) Exhibit 2 shall contain ~~the following information about the proposed facility~~:

(i) ~~The nature of the proposed generating facility, including its type, fuel, expected service life, and the gross, net, and nameplate generating capacity of each generating unit and the entire facility, as well as the facility's total projected dependable capacity, in megawatts (alternating current); the anticipated beginning date for construction; the expected commercial operation date; and estimated construction costs;~~

(i)~~(ii)~~ A color map or aerial photo ~~(a U.S. Geological Survey map or aerial photo map prepared via the State's geographic information system is preferred)~~ showing the location of the proposed facility site in relation to local highways, streets, rivers, streams, and other generally known local landmarks, with the proposed location of major equipment indicated on the map or photo, including: the generator, fuel handling equipment, plant distribution system, startup equipment, the site boundary, planned and existing pipelines, planned and existing access roads to be used to reach the generating facility, planned and existing water supplies, planned and existing electric facilities, and point(s) of interconnection with the incumbent electric service provider, including associated interconnection facilities ~~proposed site boundary and layout, with all major equipment, including the generator, fuel handling equipment, plant distribution system, startup equipment, planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities~~;

(ii)~~(iii)~~ The E911 street address, county in which the proposed facility would be located, and ~~GPS coordinates~~ latitude and longitude of the approximate center of the proposed facility site to the nearest ~~second or~~ one ten thousandth of a degree. If the E911 address is not available, Exhibit 2 shall contain a written description of the location of the proposed facility.

(iii)~~(iv)~~ In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

~~(iv)(v) A list of all needed federal, state, and local approvals related to the facility and site, identified by title and the nature of the needed approval; a copy of such approvals or a report of their status; and a copy of any application related to eligible facility and/or exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (PUHCA), as amended by the Energy Policy Act of 1992, including attachments and subsequent amendments, if any~~.~~; and~~

~~(vi) A description of the transmission facilities to which the facility will interconnect, and a color map showing their general location. If additional facilities are needed, a statement regarding whether the applicant would need to acquire rights-of-way for new facilities.~~

(3) Exhibit 3 shall contain: ~~provide a description of the need for the facility in the state and/or region, with supporting documentation.~~

(i) The nature of the generating facility, including the type and source of its power or fuel;

(ii) A description of the buildings, structures, interconnection facilities, and equipment comprising the generating facility and the manner of its operation;

(iii) A description of any fencing or other barriers that will be installed around the perimeter of the proposed facility, as well as any planned setbacks;

(iv) A description of the transmission and distribution facilities to which the facility will interconnect, and a color map showing their general location. Include the utility feeder name or substation and the voltage level of the planned interconnection. If additional facilities are needed, a statement regarding whether the applicant would need to acquire rights-of-way for new facilities;

(v) The gross and net projected maximum dependable capacity of the facility as well as the facility's nameplate capacity, expressed as megawatts (alternating current);

(vi) If the facility includes energy storage, the following information: (1) a description of the technology and the supporting components, (2) the cost of the energy storage system separate from the generating facility, (3) whether the facility is AC or DC connected, (4) how the Applicant plans to charge the energy storage system, (5) any operational restrictions included in the Interconnection Agreement, (6) output capacity in megawatts (DC), and (7) energy storage capability in megawatt-hours;

(vii) The anticipated date construction will begin;

(viii) The projected date on which the facility will begin operation;

(ix) The applicant's general plan for sale of the electricity to be generated, including the utility or other off-taker to which the applicant plans to sell the electricity, if such an off-taker has been identified;

(x) Any provisions for wheeling of the electricity, if applicable;

(xi) Arrangements for firm, non-firm or emergency generation, if applicable;
(xii) The service life of the project;
(xiii) The projected annual sales in megawatt-hours; and
(xiv) Whether the applicant intends to produce renewable energy certificates, the name of the purchaser (if the purchaser has been identified), and if the renewable energy certificates are eligible for compliance with the State's renewable energy and energy efficiency portfolio standard or any other state's renewable energy mandate.

(4) Exhibit 4 shall contain:
(i) A complete list of all federal and state licenses, permits and exemptions required for construction and operation of the generating facility and a statement of whether each has been obtained or applied for.
(ii) A copy of those that have been obtained should be filed with the application; a copy of those that have not been obtained at the time of the application should be filed with the Commission as soon as they are obtained; and~~.~~
~~(ii)~~(iii) A copy of any application or certification related to eligible facility and/or exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (PUHCA), as amended by the Energy Policy Act of 1992, including attachments and subsequent amendments, if any.

(5) Exhibit 5 shall contain:
(i) An estimate of the construction cost of the facility.
(ii) All interconnection studies that have been prepared for the facility at the time the application has been filed. Where the utility has revised an interconnection study, only the most recent revision need be provided. For purposes of Exhibit 5 and any updates, interconnection studies shall include the following:
- A feasibility study obtained from the interconnecting utility.
- A system impact study obtained from the interconnecting utility.
- A facilities study obtained from the interconnecting utility ~~detailing final interconnection facilities and network upgrade costs~~.
- An affected system study from any neighboring utilities detailing any affected system upgrades and associated costs for the ~~any~~ facility~~ that that has required affected system upgrades listed in a feasibility study, system impact study, or facilities study~~. If an affected system study has not been completed, provide a statement that the facility has been considered for affected system impacts and it has been determined that there are not any such impacts or required upgrades.
- Any interconnection agreement (including Interconnection

Construction Service Agreements, Interconnection Service Agreements, or the like) entered into with respect to the facility.

~~(ii)~~(iii) A Levelized Cost of Transmission (LCOT) (dollars per megawatt hour (alternating current)) calculation compared to the production output of the life of the facility. The calculation shall include the cost of any network and affected system upgrades required for interconnection and operation of the facility and shall include a description of the inputs used in the calculation. Where the cost of upgrades (including affected system upgrades) has been allocated to multiple generators, the applicant shall prepare an LCOT calculation assuming the full cost of the upgrade and only the output of the proposed facility; but may prepare alternative LCOT calculations, which may include (a) only the allocated cost of the upgrade and the full output of the facility; and/or (b) the full cost of the upgrade, and the total estimated output of all facilities to which upgrade costs are allocated.

~~(iii) A detailed description, including quantification, of any benefits to be received by ratepayers from any transmission upgrades, including affected system upgrades, the need for which is caused by the proposed facility, with specific reference to each upgrade identified in the relevant interconnection study.~~

(6) Exhibit 6 shall contain:

(i) A description of the need for the facility in the state and/or region, with supporting documentation;

(ii) Information specifically identifying the extent to which any regulated utility will be involved in the interconnection and operation of the facility;

(iii) A statement obtained by the applicant from any ~~the~~ electric utility to which the applicant plans to sell the electricity to be generated setting forth an assessment of the impact of such purchased power on the utility's capacity, reserves, generation mix, and capacity expansion plan;

~~(iv) If the applicant does not plan to sell to an electric utility or does not yet have a definite off-taker, provide a discussion of how the facility's output conforms to or varies from the long-range resource plan of a potential utility purchaser of the power;~~

~~(v)~~(iv) If the applicant proposes to sell energy and capacity from the facility to a purchaser who is subject to a statutory or regulatory mandate with respect to its energy sourcing, explain how, if at all, the facility will assist or enable compliance with that mandate. Provide any contracts that support that compliance; and

~~(vi)~~(v) Provide any power purchase agreements, renewable energy certificate sale contracts, or contracts for compensation for environmental attributes for the output of the facility.

(7) Exhibit 7 shall contain:

(i) A statement detailing the experience and expertise of the persons who will develop, design, construct and operate the project to the extent such persons are known at the time of the application;

(ii) A copy of the applicant's most recent annual report to stockholders, if applicable;

(iii) The most current available balance sheet of the applicant;

(iv) The most current available income statement of the applicant;

(v) An economic feasibility study of the project; and

(vi) A statement of the actual financing arrangements entered into i~~i~~n connection with the project to the extent known at the time of the application.

(8) Exhibit 8 shall contain:

(i) The projected annually hourly production profile for the first full year of operation of the facility in kilowatt-hours (alternating current), including an explanation of potential factors influencing the hourly production profile;

(ii) If the facility's maximum generation has the capability to exceed the nameplate capacity (alternating current), include a description of what factors or component will limit production;

(iii) A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser;

(iv) A one-line diagram, or equivalent, that illustrates the planned arrangement and interconnection of the entire facility; and

(v) A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

(9)~~(4)~~ The application shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant.

(10)~~(5)~~ The application shall be accompanied by prefiled direct testimony incorporating and supporting the application.

(11)~~(6)~~ The Chief Clerk will deliver 2 copies ~~copy~~ of the application and the notice to the State Environmental Review Clearinghouse Coordinator of the Office of Policy and Planning in the Department of Administration for distribution by the Clearinghouse Coordinator to State agencies having an interest in the application ~~proposed generating facility~~.

(12)~~(7)~~ Contemporaneous with the filing of the application with the Commission, all applicants proposing a generating facility that will use natural gas must provide written notice of the filing to the natural gas local distribution company or municipal gas system providing service or franchised to provide service at the location of the proposed generating facility.

(c) Confidential Information. If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

(d) Procedure upon Receipt of Application. No later than ten (10) business days after the application is filed with the Commission, the Public Staff shall, and any other party in interest may, file with the Commission and serve upon the applicant a notice regarding whether the application is complete and identifying any deficiencies. If the Commission determines that the application is not complete, the applicant will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue a procedural order setting the matter for hearing, requiring public notice, and dealing with other procedural matters.

(e) The Certificate.

(1) The certificate shall specify the date the certificate was issued; the name and address of the certificate holder; the type, capacity, and location of the facility; and the conditions, if any, upon which the certificate is granted.

(2) The certificate shall be subject to revocation if (a) any of the federal, state, or local licenses or permits required for construction and operation of the generating facility not obtained or, having been obtained, are revoked pursuant to a final, non-appealable order; (b) required reports or fees are not filed with or paid to the Commission; and/or (c) the Commission concludes that the certificate holder filed with the Commission information of a material nature that was inaccurate and/or misleading at the time it was filed; provided that, prior to revocation pursuant to any of the foregoing provisions, the certificate holder shall be given thirty (30) days' written notice and opportunity to cure.

(3) ~~The certificate must be renewed if the applicant does not begin construction within three years after the date of the Commission order granting the certificate.~~ The certificate shall expire if the applicant does not begin construction within three years after the certificate is issued.

(i) The certificate holder shall file with the Commission a description of the construction progress pursuant to subsection (f) of this Rule prior to the expiration of the certificate. The Commission may revoke the certificate if the certificate holder fails to file a construction progress update prior to the expiration of the certificate.

(ii) The certificate may be renewed by re-compliance with the requirements set forth in subsection (b) of this Rule.

(iii) Applications for renewal must be filed no later than 90 calendar days prior to the expiration of the certificate. An application for renewal that is filed no later than 90 calendar days prior to the expiration of the certificate will be considered timely regardless of when a new certificate is issued; and upon issuance the new certificate will be deemed to have issued on the date of expiration of the original certificate.

(iv) Amendments and transfers of certificates pursuant to subsection (d)(4) of this Rule will not alter the expiration date of a certificate.

(4) A certificate holder must notify the Commission in writing of any plans to sell, ~~transfer~~, or assign the certificate and the generating facility or of any significant revisions to the information set forth in subsections (b)(1) thru (b)(8) of this Rule, and the Commission will order such proceedings as necessary to address the proposed plans or revisions. The following changes in information are exemplary of changes that require an amendment to the certificate issued for the facility: a transfer of the certificate or the facility, a change in the facility owner's name, a change in the fuel source, a change in the generating capacity of the facility, a change in the point(s) of interconnection, and the addition of land to the project area. The following changes in information are exemplary of changes that require notice to the Commission, but do not require an amendment to the certificate: a change in the facility owner's contact information, or a change in the upstream ownership of the facility, a reduction in the footprint of the facility, and the movement of equipment or access roads within the footprint of the facility as filed with the Commission when the certificate was approved.

(f) Reporting. All ~~applicants~~ certificate holders must submit annual progress reports and any revisions in cost estimates until construction is completed. If transmission upgrade costs estimated by the interconnecting utility or an affected system are revised subsequent to the approval of the application and issuance of the certificate, the certificate holder must file notice with the Commission of such changes no later than 30 days after receiving notice from the relevant utility of the revised cost estimates.

(1) If the applicant receives additional or revised interconnection studies or agreements for the facility while its application is pending, the applicant shall file such revised or additional studies, along with a summary of any changes to interconnection costs, upgrade costs, or affected system upgrade costs assigned to the facility, within 30 days after receipt. If there are any changes to upgrade or affected system upgrade costs allocated to the facility, applicant shall file updated LCOT calculations reflecting such changes.