DEC / DEP Exhibit 6

Clean and Redlined Copies of Notice of Commitment Form for QFs Eligible for Schedule PP

Docket No. E-100, Sub 194

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A SMALL QUALIFYING FACILITY ELIGIBLE FOR SCHEDULE PP TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

This notice of commitment form establishes the procedure for a qualifying facility ("QF") with a nameplate capacity up to 1 MWAC that is requesting to establish a legally enforceable obligation ("LEO") and to commit to sell the output of a proposed QF generating facility pursuant to Duke Energy Carolinas, LLC's or Duke Energy Progress, LLC's (the "Company") Schedule PP (NC) and standard offer power purchase agreement and terms and conditions. QFs submitting this form after November 1, 2023, are committing to sell the full output of the generating facility to the Company pursuant to Schedule PP and the avoided cost rates and terms filed with Commission in Docket No. E-100, Sub 194, until such time as new rates are filed with the Commission in the next biennial avoided cost proceeding. Eligibility of QFs above 100 kW for Schedule PP shall be determined under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW per Company) based upon the Effective Date of the LEO established under this Notice of Commitment form. Please note that a different form is required for QFs with a nameplate capacity greater than 1 MWAC seeking to commit to sell their output to the Company under a negotiated power purchase arrangement as provided for in N.C. Gen. Stat. § 62-156(c) and 18 C.F.R. 292.304(d)(2).

1. Delivery; Notices to Company. The QF shall deliver, via email, its executed Notice of Commitment to:

   Duke Energy – Distributed Energy Resources
   Attn.: Renewable Contract Manager
   PPA@duke-energy.com

Any subsequent notice that a QF may be required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same address.

2. Seller Information. The name, address, and contact information for Seller is:

   Legal Name of Seller: ____________________________________

   Contact Person: ______________________ Telephone: ________________________

   Address: ____________________________ Email: ____________________________

3. Commitment to Sell. By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of Seller's qualifying facility (the "Facility") for specified future delivery term of [2 years, 10 years] (the "Delivery Term"), Seller hereby commits to sell to the Company all of the electrical output of the Seller's Facility ("Notice of Commitment").

4. Certifications. By execution and submittal of this Notice of Commitment to sell the output of the Facility, Seller certifies as follows:

Eligibility for Schedule PP
Seller is a qualifying facility ("QF") with a maximum nameplate capacity of 1,000 kW and is eligible for the Company's Schedule PP.

Report of Proposed Construction (Rule R8-65)
Seller has filed a report of proposed construction for its ____ kW (net capacity ac) Facility with the North Carolina Utilities Commission ("NCUC") pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. _______.

Interconnect to Generator to Company's System
Seller is either currently connected to Company's system or is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and has either submitted the NCIP Attachment 6 Interconnection Request Application Form for Certified Inverter-Based Generating Facilities No Larger Than 20 kW or has submitted the NCIP Attachment 2 Interconnection Request Application Form requesting a Maximum Generating Capacity less than or equal to 1 MWAC and the Company has notified the Seller-Interconnection Customer that its Interconnection Request is complete and the following queue number has been assigned [insert queue number].

Other Seller QFs within 1-10 miles
Seller is providing the QF self-certification or other documentation describing the location and nameplate capacity for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

Site Control
Seller is providing reasonable evidence of site control for the entire contracting term.

Commercial Viability and Financial Commitment
Seller commits to provide upon the Company's request (i) a list of all acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits; and (ii) reasonable evidence that the Seller is financially committed to constructing the QF and selling and delivering capacity and energy to the Company for term of the proposed contracting term.

5. Effective Date. This Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means the date on which a completed electronic copy of this Notice of Commitment, executed by Seller, is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after

regular business hours or on days that are not business days shall be deemed submitted on the next business day.

6. LEO Date. By execution and submittal of this Notice of Commitment, and assuming that the certifications provided herein are accurate, Seller acknowledges that the legally enforceable obligation date ("LEO Date") for the Facility will be established as of the Submittal Date. The LEO Date will be used to determine Seller's eligibility for the rates, terms and conditions of the Company's currently effective Schedule PP.

7. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect upon: (i) execution of a PPA between Seller and Company or, (ii) if such Seller does not execute a PPA, sixty (60) days after Company's delivery of an "executable" PPA to the QF by the Company, that contains all information necessary for execution and which the Company has requested that the QF execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Interconnection Agreement from Company. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period or termination, as identified above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

The undersigned is duly authorized to execute this Notice of Commitment for the Seller:

____
[Name]

____
[Title]

____
[Company]

____
[Date]

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A SMALL QUALIFYING FACILITY ELIGIBLE FOR SCHEDULE PP TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

This notice of commitment form establishes the procedure for a qualifying facility ("QF") with a nameplate capacity up to 1 MWAC that is requesting to establish a legally enforceable obligation ("LEO") and to commit to sell the output of a proposed QF generating facility pursuant to Duke Energy Carolinas, LLC's or Duke Energy Progress, LLC's (the "Company") Schedule PP (NC) and standard offer power purchase agreement and terms and conditions. QFs submitting this form after November 1, ~~2021~~2023, are committing to sell the full output of the generating facility to the Company pursuant to Schedule PP and the avoided cost rates and terms filed with Commission in Docket No. E-100, Sub ~~175~~194, until such time as new rates are filed with the Commission in the next biennial avoided cost proceeding. Eligibility of QFs above 100 kW for Schedule PP shall be determined under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW per Company) based upon the Effective Date of the LEO established under this Notice of Commitment form. Please note that a different form is required for QFs with a nameplate capacity greater than 1 MWAC seeking to commit to sell their output to the Company under a negotiated power purchase arrangement as provided for in N.C. Gen. Stat. § 62-156(c) and 18 C.F.R. 292.304(d)(2).

1. Delivery; Notices to Company. The QF shall deliver, via email, its executed Notice of Commitment to:

   Duke Energy – Distributed Energy ~~Technologies~~Resources
   Attn.: ~~Wholesale~~ Renewable Contract Manager
   ~~DERContracts@duke-energy.com~~

   PPA@duke-energy.com

Any subsequent notice that a QF may be required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same address.

2. Seller Information. The name, address, and contact information for Seller is:

   Legal Name of Seller: ________________________________

   Contact Person: ______________________ Telephone: ________________________

   Address: ____________________________ Email: ____________________________

3. Commitment to Sell. By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of Seller's qualifying facility (the "Facility") for specified future delivery term of [2 years, 10 years] (the "Delivery Term"), Seller hereby commits to sell to the Company all of the electrical output of the Seller's Facility ("Notice of Commitment").

4. Certifications. By execution and submittal of this Notice of Commitment to sell the output of the Facility, Seller certifies as follows:

Eligibility for Schedule PP
Seller is a qualifying facility ("QF") with a maximum nameplate capacity of 1,000 kW and is eligible for the Company's Schedule PP.

Report of Proposed Construction (Rule R8-65)
Seller has filed a report of proposed construction for its ____ kW (net capacity ac) Facility with the North Carolina Utilities Commission ("NCUC") pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. _______.

~~Application to~~ Interconnect to Generator to Company's System
Seller is either currently connected to Company's system or is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and has either submitted the NCIP Attachment 6 Interconnection Request Application Form for Certified Inverter-Based Generating Facilities No Larger Than 20 kW or has submitted the NCIP Attachment 2 Interconnection Request Application Form requesting a Maximum Generating Capacity less than or equal to 1 MWAC and the Company has notified the Seller-Interconnection Customer that its Interconnection Request is complete and the following queue number has been assigned [insert queue number].

Other Seller QFs within 1-10 miles
Seller is providing the QF self-certification or other documentation describing the location and nameplate capacity for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

Site Control
Seller is providing reasonable evidence of site control for the entire contracting term.

Commercial Viability and Financial Commitment
Seller commits to provide upon the Company's request (i) a list of all acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits; and (ii) reasonable evidence that the Seller is financially committed to constructing the QF and selling and delivering capacity and energy to the Company for term of the proposed contracting term.

5. Effective Date. This Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means ~~(a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the~~

~~Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d)~~ the date on which ~~an~~a completed electronic copy of this Notice of Commitment, executed by Seller, is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.~~n~~

6. LEO Date. By execution and submittal of this Notice of Commitment, and assuming that the certifications provided herein are accurate, Seller acknowledges that the legally enforceable obligation date ("LEO Date") for the Facility will be established as of the Submittal Date. The LEO Date will be used to determine Seller's eligibility for the rates, terms and conditions of the Company's currently effective Schedule PP.

7. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect upon: (i) execution of a PPA between Seller and Company or, (ii) if such Seller does not execute a PPA, sixty (60) days after Company's delivery of an "executable" PPA to the QF by the Company, that contains all information necessary for execution and which the Company has requested that the QF execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Interconnection Agreement from Company. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period or termination, as identified above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

The undersigned is duly authorized to execute this Notice of Commitment for the Seller:

____
[Name]

____
[Title]

____
[Company]

____
[Date]

DEC / DEP Exhibit 7

Clean and Redlined Copies of Notice of Commitment Form for QFs Larger than 1MW

Docket No. E-100, Sub 194

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY GREATER THAN 1MW$_{AC}$ TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

(North Carolina)

This notice of commitment form establishes a binding legally enforceable obligation ("LEO") on behalf of a qualifying facility ("QF") with a nameplate capacity greater than 1 MW$_{AC}$, further described as "Seller" below, committing to sell and deliver the output of a proposed QF generating facility to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") as provided for in N.C. Gen. Stat. § 62-156(b) and 18 C.F.R. 292.304(d)(3).

The QF shall deliver, via email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy Resources
Attn.: Renewable Contract Manager
PPA@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same email address specified above.

This form may also be used by a QF proposing to materially alter its generating facility to integrate an energy storage system and committing to sell the output of the modified generating facility to the Company. Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.

Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ____________________
Contact Person: __________________ Telephone: ______________________
Address: ________________________ Email: __________________________

By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of the Facility for the Delivery Term (together will all completed Attachments hereto, the "Notice of Commitment"), Seller certifies as follows and is providing the following documentation to the Company:

1. Seller meets the requirements and has obtained certification from the Federal Energy Regulatory Commission ("FERC") to operate as a QF. Seller is providing documentation in Attachment A demonstrating the following:

   A. Seller has obtained self-certification of QF status filed with the FERC in Docket No. QF __________ (the "Facility"), or is otherwise providing documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207; or,

B. If participating in the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC Energy Storage System Retrofit Study Process, Seller is proposing to materially alter an existing QF to integrate an energy storage system to be fueled by the QF and has obtained certification of the modified QF in Docket No. QF __________ and has provided the new QF self-certification and written notice of the QF's commitment to construct the energy storage system to the North Carolina Utilities Commission ("Commission") in Docket No.__________ where the QF's Certificate of Public Convenience and Necessity was originally issued.

Seller shall also provide in Attachment A documentation for all other QFs located within one mile of the project or within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

2. Seller's QF is currently operating or is proposed to be constructed and to interconnect to the Company's system at the location described in Attachment B (the "Project Site"). If Seller is not directly interconnected to the Company's System, Seller shall be responsible for making all necessary transmission arrangements with its interconnected electric utility to deliver its power to the Company pursuant to 18 C.F.R. 292.303(d).

3. Seller shall also provide in Attachment B all material information required for the Company to provide Seller an executable power purchase agreement within 30 days of the date of this notice of commitment. If information provided by Seller is not sufficient, the Company shall provide the Seller written notice providing an opportunity to cure such failure by the close of business on the tenth (10) business day following the posted date of such notice. The failure to provide the information requested within this period shall result in the Notice of Commitment being terminated pursuant to Section 8.

4. Commitment to Sell Power for Specified Future Delivery Term. Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years, other], (the "Delivery Term") as follows: (a) where Seller's QF is currently interconnected to the Company's System, within 365 days of the Submittal Date (as defined below), and (b) where the Seller is a new Interconnection Customer of the Company (or where a new interconnection request is submitted for an interconnected QF Seller which includes a new in-service date), by a date that is no later than 90 days after the in-service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company. Provided that Seller is making good faith efforts to advance the project as contemplated in the interconnection request or interconnection agreement and has provided reasonable assurances of such in writing to the Company, Seller shall be given day-for-day extensions on its in-service date for delays to the in-service date which are not caused by or attributable to Seller, or any party under its direction or control, and which do not result from the fault, negligence, act or inaction of Seller or any party under its direction or control. By execution of this Form, Seller represents that the QF is commercially viable and financially committed to delivering its full electrical output to the Company for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

5. The documents attached hereto as Attachment C are provided to demonstrate Seller's commercial viability and financial commitment to sell and deliver power as of the Submittal Date for the future Delivery Term.

6. The mutually-binding legally enforceable obligation established by this Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means the date on which a completed electronic copy of this Notice of Commitment, executed by Seller, is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays).Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

7. LEO Date. By execution and submittal of this Notice of Commitment, and assuming that the certifications provided herein are accurate, Seller acknowledges that the date of the QF's binding legally enforceable obligation date to sell the Facility's full capacity and energy output to the Company ("LEO Date") will be the Submittal Date. Rates for purchases from the Seller's QF Facility will be based on the Company's avoided costs as of the LEO Date, calculated using data current as of the LEO Date.

8. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect in each of the following circumstances:

   a. Upon execution of a PPA between Seller and Company.

   b. If Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue.

   c. If Seller does not execute a PPA within 90 days after the Company delivers an executable PPA to the Seller that contains all information necessary for execution and which the Company has requested the Seller to execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Facilities Study Agreement from Company. Notwithstanding the foregoing, if the PPA proposed by the Company becomes the subject of arbitration or complaint proceeding, the deadline for execution of the PPA shall be tolled upon the filing of the pleading commencing such proceeding and thereafter the deadline for execution of the PPA will be as directed by the Commission.

   d. If the Seller ceases to have control of the Project Site; ceases to be certified as a QF with FERC or ceases to be certificated by the Commission, if required, and any such deficiency has not been cured within ten (10) business days of written notice by the Company.

   e. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period, as identified in subsection 8.(c) above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

I swear or affirm, in my capacity as a duly-appointed officer of the Seller, that I have personal knowledge of the facts and information presented in this Notice of Commitment, I am competent to testify to those facts, and I have authority to make this binding legally enforceable obligation to the Company on behalf of Seller. I further swear or affirm that all of the statements and representations made in this Notice of Commitment are true and correct as of the date hereof. I further swear or affirm that Seller will comply will all requirements of this Notice of Commitment.

____
[Name]

____
[Title]

____
[Company]

____
[Date]

Attachment A to Notice of Commitment Form

[*Seller Information, QF Certification, and Affiliated QFs*]

1. Seller Information. The name, address, and contact information for Seller is:

   Name: ___________________________ Telephone: _________________________

   Address: _________________________ Email: ____________________________

2. Seller is providing its QF self-certification or other documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207.

3. Seller is providing the QF self-certification or other documentation for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller. Seller shall also provide a description of the organizational structure and chart of upstream developer, if applicable, and describe the affiliate relationship between Seller and other QFs within 10 miles of the project.

Attachment B to Notice of Commitment Form

[*Information Required to Complete PPA*]

The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and commits to provide Seller an executable PPA within 30 days of receipt of all project information reasonably required for the development of the PPA, including, but not limited to:

a. Facility Name and address of Project Site;
b. Description of Facility (include number, manufacturer and model of Facility generating units, and layout). Also, describe if storage is included;
c. Generation technology and other related technology applicable to the Facility;
d. Fuel type (s) and source (s);
e. Plans to obtain, or actual fuel and transportation agreements, if applicable;
f. Maximum design capacity AC and DC (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;
g. Site Map (include location and layout of the Facility, equipment, and other site details for the Project Site);
h. Delivery Point Diagram (include Delivery Point, metering, Facility substation)
i. Where QF is or will be interconnected to an electrical system other than the Company's, plans to obtain, or actual electricity transmission agreements with the interconnected system to deliver power to Company;
j. Quantity, firmness, and timing of daily and monthly power deliveries, including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;
k. Ability, if any, of QF to respond to dispatch orders from the Company and, if applicable, whether solar QF plans to operate facility as a Controlled Solar Generator*;
l. Anticipated commencement date for delivery of electric output;
m. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;
n. Interconnection Agreement status and estimated date for execution of Interconnection Agreement;
o. Estimated date for Financing Commitment*,
p. Estimated date for Final System Design* under Interconnection Agreement
q. Estimated date for Commencement Readiness Requirements* and
r. Proposed contracting term for the sale of electric output to the Company.

*Capitalized terms unless defined herein shall have the same meaning specified in the Companies' negotiated form of power purchase agreement for large QFs above 1MW accessible on [Duke website], unless otherwise specified herein.

Attachment C to Notice of Commitment Form

[*Information Required to Demonstrate Commercial Viability and Financial Commitment*]

Seller provides the following information in order to demonstrate commercial viability and financial commitment to sell and deliver power over the specified Delivery Term

1. Certificate of Public Convenience and Necessity; or Report of Proposed Construction.

   a. ____Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _____ kW (net capacity$_{ac}$) Facility from the NCUC pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. ____.

   b. Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its ____ kW (net capacity$_{ac}$) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. ___.

   c. Seller is proposing to co-locate an _____ kW (net capacity$_{ac}$) energy storage system at a generating facility that previously obtained a CPCN for the construction of a _____ kW (net capacity$_{ac}$) QF generating facility in Docket No. ____ and the QF has provided written notice to the NCUC of the planned energy storage addition to the QF.

2. Interconnection – Reasonable evidence that Seller is interconnected to the Company's system, has made transmission arrangements to deliver its power to the Company's system, or has requested to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and the Seller has met all applicable requirements to commence the interconnection study process under the Definitive Interconnection Study Process, including without limitation providing the Section 4.4.1 initial security requirement and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5.

3. Site Control – Reasonable evidence of site control for the entire contracting term

4. Project Development – Please provide a current status update on the development of the Facility, including anticipated timelines for:
   a. completion of key QF milestones specified in Attachment B,
   b. proof of payment of applicable permitting and other application fees,
   c. the procurement of any long-lead time materials,
   d. execution of construction agreements or EPC contracts to construct the Facility,
   e. execution of third-party Transmission Agreements and other agreements or events necessary to achieve commercial operation of the facility within 365 days of the Submittal Date.

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY GREATER THAN 1MW$_{AC}$ TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

(North Carolina)

This notice of commitment form establishes a binding legally enforceable obligation ("LEO") on behalf of a qualifying facility ("QF") with a nameplate capacity greater than 1 MW$_{AC}$, further described as "Seller" below, committing to sell and deliver the output of a proposed QF generating facility to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") as provided for in N.C. Gen. Stat. § 62-156(b) and 18 C.F.R. 292.304(d)(3).

The QF shall deliver, via email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy ~~Technologies~~Resources
Attn.: ~~Wholesale~~ Renewable Contract Manager

~~DERContracts@duke-energy.com~~

PPA@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same email address specified above.

This form may also be used by a QF proposing to materially alter its generating facility to integrate an energy storage system and committing to sell the output of the modified generating facility to the Company. Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.

Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ______________________
Contact Person: ____________________ Telephone: ________________________
Address: __________________________ Email: _____________________________

By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of the Facility for the Delivery Term (together will all completed Attachments hereto, the "Notice of Commitment"), Seller certifies as follows and is providing the following documentation to the Company:

1. Seller meets the requirements and has obtained certification from the Federal Energy Regulatory Commission ("FERC") to operate as a QF. Seller is providing documentation in Attachment A demonstrating the following:

   A. Seller has obtained self-certification of QF status filed with the FERC in Docket No. QF __________ (the "Facility"), or is otherwise providing documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207; or,

B. If participating in the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC Energy Storage System Retrofit Study Process, Seller is proposing to materially alter an existing QF to integrate an energy storage system to be fueled by the QF and has obtained certification of the modified QF in Docket No. QF __________ and has provided the new QF self-certification and written notice of the QF's commitment to construct the energy storage system to the North Carolina Utilities Commission ("Commission") in Docket No.__________ where the QF's Certificate of Public Convenience and Necessity was originally issued.

Seller shall also provide in Attachment A documentation for all other QFs located within one mile of the project or within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

2. Seller's QF is currently operating or is proposed to be constructed and to interconnect to the Company's system at the location described in Attachment B (the "Project Site"). If Seller is not directly interconnected to the Company's System, Seller shall be responsible for making all necessary transmission arrangements with its interconnected electric utility to deliver its power to the Company pursuant to 18 C.F.R. 292.303(d).

3. Seller shall also provide in Attachment B all material information required for the Company to provide Seller an executable power purchase agreement within 30 days of the date of this notice of commitment. If information provided by Seller is not sufficient, the Company shall provide the Seller written notice providing an opportunity to cure such failure by the close of business on the tenth (10) business day following the posted date of such notice. The failure to provide the information requested within this period shall result in the Notice of Commitment being terminated pursuant to Section 8.

4. Commitment to Sell Power for Specified Future Delivery Term. Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years, other], (the "Delivery Term") as follows: (a) where Seller's QF is currently interconnected to the Company's System, within 365 days of the Submittal Date (as defined below), and (b) where the Seller is a new Interconnection Customer of the Company (or where a new interconnection request is submitted for an interconnected QF Seller which includes a new in-service date), by a date that is no later than 90 days after the in-service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company. Provided that Seller is making good faith efforts to advance the project as contemplated in the interconnection request or interconnection agreement and has provided reasonable assurances of such in writing to the Company, Seller shall be given day-for-day extensions on its in-service date for delays to the in-service date which are not caused by or attributable to Seller, or any party under its direction or control, and which do not result from the fault, negligence, act or inaction of Seller or any party under its direction or control.~~.~~ By execution of this Form, Seller represents that the QF is

commercially viable and financially committed to delivering its full electrical output to the Company for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

5. The documents attached hereto as Attachment C are provided to demonstrate Seller's commercial viability and financial commitment to sell and deliver power as of the Submittal Date for the future Delivery Term.

6. The mutually-binding legally enforceable obligation established by this Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means ~~(a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d)~~ the date on which ~~an~~a completed electronic copy of this Notice of Commitment, executed by Seller, is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays).Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

7. LEO Date. By execution and submittal of this Notice of Commitment, and assuming that the certifications provided herein are accurate, Seller acknowledges that the date of the QF's binding legally enforceable obligation date to sell the Facility's full capacity and energy output to the Company ("LEO Date") will be the Submittal Date. Rates for purchases from the Seller's QF Facility will be based on the Company's avoided costs as of the LEO Date, calculated using data current as of the LEO Date.

8. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect in each of the following circumstances:

   a. Upon execution of a PPA between Seller and Company.

   b. If Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue.

   c. If Seller does not execute a PPA within 90 days after the Company delivers an executable PPA to the Seller that contains all information necessary for execution and which the Company has requested the Seller to execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Facilities Study Agreement from Company. Notwithstanding the foregoing, if the PPA proposed by the Company becomes the subject of arbitration or complaint proceeding, the deadline for execution of the PPA shall be tolled upon the filing of the pleading commencing such proceeding and thereafter the deadline for execution of the PPA will be as directed by the Commission.

d. If the Seller ceases to have control of the Project Site; ceases to be certified as a QF with FERC or ceases to be certificated by the Commission, if required, and any such deficiency has not been cured within ten (10) business days of written notice by the Company.

e. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period, as identified in subsection 8.(c) above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

I swear or affirm, in my capacity as a duly-appointed officer of the Seller, that I have personal knowledge of the facts and information presented in this Notice of Commitment, I am competent to testify to those facts, and I have authority to make this binding legally enforceable obligation to the Company on behalf of Seller. I further swear or affirm that all of the statements and representations made in this Notice of Commitment are true and correct as of the date hereof. I further swear or affirm that Seller will comply will all requirements of this Notice of Commitment.

____
[Name]

____
[Title]

____
[Company]

____
[Date]

Attachment A to Notice of Commitment Form

[*Seller Information, QF Certification, and Affiliated QFs*]

1. Seller Information. The name, address, and contact information for Seller is:

   Name: ___________________________ Telephone: _________________________

   Address: _________________________ Email: ____________________________

2. Seller is providing its QF self-certification or other documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207.

3. Seller is providing the QF self-certification or other documentation for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller. Seller shall also provide a description of the organizational structure and chart of upstream developer, if applicable, and describe the affiliate relationship between Seller and other QFs within 10 miles of the project.

Attachment B to Notice of Commitment Form

[*Information Required to Complete PPA*]

The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and commits to provide Seller an executable PPA within 30 days of receipt of all project information reasonably required for the development of the PPA, including, but not limited to:

a. Facility Name and address of Project Site;
b. Description of Facility (include number, manufacturer and model of Facility generating units, and layout). Also, describe if storage is included;
c. Generation technology and other related technology applicable to the Facility;
d. Fuel type (s) and source (s);
e. Plans to obtain, or actual fuel and transportation agreements, if applicable;
f. Maximum design capacity AC and DC (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;
g. Site Map (include location and layout of the Facility, equipment, and other site details for the Project Site);
h. Delivery Point Diagram (include Delivery Point, metering, Facility substation)
i. Where QF is or will be interconnected to an electrical system other than the Company's, plans to obtain, or actual electricity transmission agreements with the interconnected system to deliver power to Company;
j. Quantity, firmness, and timing of daily and monthly power deliveries, including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;
k. Ability, if any, of QF to respond to dispatch orders from the Company and, if applicable, whether solar QF plans to operate facility as a Controlled Solar Generator*;
l. Anticipated commencement date for delivery of electric output;
m. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;
n. Interconnection Agreement status and estimated date for execution of Interconnection Agreement;
o. Estimated date for Financing Commitment*,
p. Estimated date for Final System Design* under Interconnection Agreement
q. Estimated date for Commencement Readiness Requirements* and
r. Proposed contracting term for the sale of electric output to the Company.

*Capitalized terms unless defined herein shall have the same meaning specified in the Companies' negotiated form of power purchase agreement for large QFs above 1MW accessible on [Duke website], unless otherwise specified herein.

Attachment C to Notice of Commitment Form

[*Information Required to Demonstrate Commercial Viability and Financial Commitment*]

Seller provides the following information in order to demonstrate commercial viability and financial commitment to sell and deliver power over the specified Delivery Term

1. Certificate of Public Convenience and Necessity; or Report of Proposed Construction.

   a. ____Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _____ kW (net capacity$_{ac}$) Facility from the NCUC pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. ____.

   b. Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its ____ kW (net capacity$_{ac}$) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. ___.

   c. Seller is proposing to co-locate an _____ kW (net capacity$_{ac}$) energy storage system at a generating facility that previously obtained a CPCN for the construction of a _____ kW (net capacity$_{ac}$) QF generating facility in Docket No. ____ and the QF has provided written notice to the NCUC of the planned energy storage addition to the QF.

2. Interconnection – Reasonable evidence that Seller is interconnected to the Company's system, has made transmission arrangements to deliver its power to the Company's system, or has requested to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and the Seller has met all applicable requirements to commence the interconnection study process under the Definitive Interconnection Study Process, including without limitation providing the Section 4.4.1 initial security requirement and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5.
3. Site Control – Reasonable evidence of site control for the entire contracting term
4. Project Development – Please provide a current status update on the development of the Facility, including anticipated timelines for:
   a. completion of key QF milestones specified in Attachment B,
   b. proof of payment of applicable permitting and other application fees,
   c. the procurement of any long-lead time materials,
   d. execution of construction agreements or EPC contracts to construct the Facility,
   e. execution of third-party Transmission Agreements and other agreements or events necessary to achieve commercial operation of the facility within 365 days of the Submittal Date.

DEC / DEP Public Redacted Exhibit 8

Additional Technical Support for Inputs to DEC's & DEP's Avoided Energy and Capacity Cost Calculations

Docket No. E-100, Sub 194

North Carolina Avoided Cost Filing
Docket No. E-100, Sub 194
DEC/DEP Exhibit 8 – Technical Support
Avoided Capacity and Energy Inputs and Rate Design

This Exhibit provides additional detail on the following topics:

I. First Year of Avoidable Capacity Need

In calculating avoided capacity costs, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") each utilized their first year of undesignated and avoidable capacity need as identified in the Companies' 2023 Carbon Plan and Integrated Resource Plan ("CPIRP") filed on August 17, 2023 in Docket No. E-100, Sub 190. As described in Appendix C to the CPIRP, the Companies determined the first year of resource need for DEC and DEP using recommended Portfolio P3 Base.[1] In this calculation, the Companies included only incremental resource additions that are considered designated or mandated. Designated resources include those projects that are committed, already in progress, have been granted a Certificate of Public Convenience and Necessity ("CPCN") or Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN"), and smaller capacity additions such as unit uprates that are included as part of the Companies' normal business operations, firm market purchases, or EE/DSM programs.

Mandated renewable energy resources are renewable resources needed to meet renewable requirements such as NC REPS, competitive procurement of renewable energy ("CPRE") requirements, or other requirements mandated by the North Carolina Utilities Commission (the "Commission") or the Public Service Commission of South Carolina ("PSCSC"). These resources are also included in committed resources for the first year of resource need calculation.

Undesignated resources include resources in development that have not established a legally enforceable obligation committing to sell to power to DEC or DEP for a specified future term (e.g., QF notice of commitment or purchase power contracts) as well as projected resources in the IRP that do not have a CPCN or CECPCN. Undesignated resources are not included as committed resources for the first year of resource need calculation. A resource moves from undesignated to designated or mandated if current contracts become extended or additional resources are approved by the Commissions when CPCN or CECPNs are granted. As these resources become designated, the timing of the first need may change by reflecting the additional committed resources.

Additionally, firm market purchases, which include wholesale contracts, including renewable contracts, were assumed to be committed resources through the end of their currently contracted period. There is no guarantee that the counterparty will choose to sell, or the Companies will agree to purchase its capacity after the contracted time frame. Beyond the contract period, the seller may elect to retire the resource or sell the output to an entity other than the Companies. As such, contracted resources are deemed designated only for the duration of their legally enforceable contract.

Only designated and mandated resources as described above were considered committed resources when determining the first resource need that can then be used for other regulatory purposes such as the first year of undesignated capacity need for developing avoided cost rates. As such, a list of resources included for DEC and DEP is below:

- Designated and mandated renewable resources;

[1] CPIRP Appendix C at 112-13.

- Nuclear uprates;
- CC uprates;
- Designated wholesale contracts;
- DSM/EE programs;
- Bad Creek runner uprates (DEC only); and
- Lincoln CT project (DEC only).

The Companies have replicated Figure C-12 and Figure C-13 from Appendix C to the CPIRP. Figure C-12 demonstrates the first avoidable resource need for DEC is in 2028, while Figure C-13 demonstrates the first avoidable resource need for DEP is in 2024.

Figure C-12: DEC First Year of Resource Need (P3 Base)

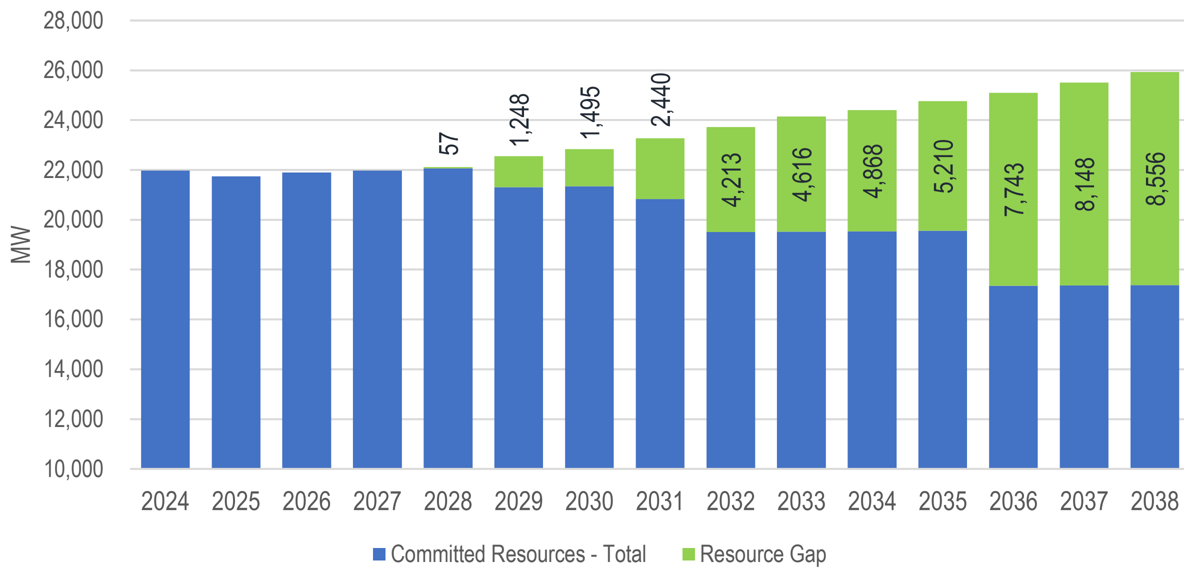
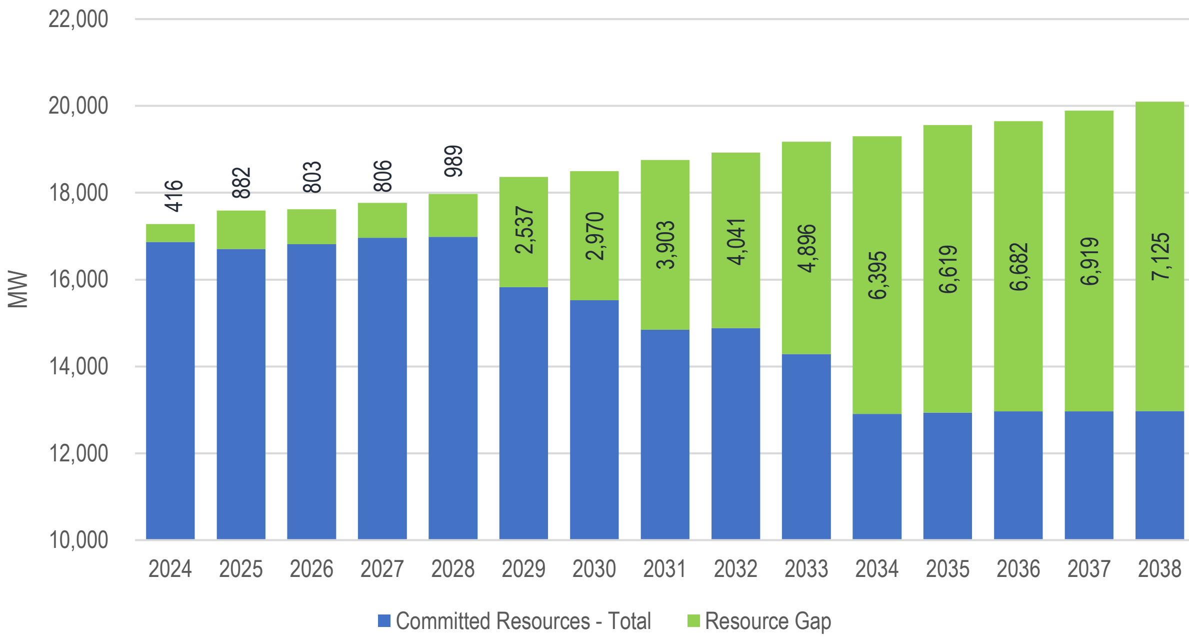


Figure C-13: DEP First Year of Resource Need (P3 Base)



II. <u>CT Capital Cost</u>

The Companies used the greenfield economies of scale methodology to calculate the CT Capital Cost. This methodology assesses the avoided capacity cost by taking the U.S. Energy Information Administration's ("EIA") most current published overnight cost of a CT unit and applying a percentage decrement to reflect the economies of scale associated with a four-unit CT site in the Carolinas.[2] This Exhibit provides supporting information for the standardized and repeatable methodology, which has been developed by the Companies and Dominion Energy North Carolina ("DENC")[3] and accepted by the Public Staff for purposes of developing the avoided CT cost.

The table below shows the EIA data that reflects the overnight cost to construct a single unit at a greenfield site ($793/kW, 2022 dollars). Given the supply chain constraints and high inflation experienced over the past couple of years, the Companies escalated the overnight cost from 2022 dollars to 2023 dollars using technology-specific Burns & McDonnell[4] cost estimates. Burns & McDonnell data shows that the cost to construct a CT plant increased approximately 36.6% during the two-year period from 2021 to 2023. The Companies assumed that half of the 36.6% escalation occurred from 2021 to 2022 and the other half occurred from 2022 to 2023. Thus, the Companies applied an 18.3% escalation to the 2023 EIA data (2022 dollars) to arrive at a cost of $938/kW in 2023 dollars.

The Companies' practice is to build multiple units at a site to realize infrastructure economies of scale savings for customers including land, roads, buildings, electrical interconnection, etc. In 2021 Sub 175 proceeding, the Companies and DENC independently developed estimates for the common infrastructure costs for a four-unit greenfield site. After adjusting for the carrying costs associated with the economies of scale adjustment,[5] the Companies' estimate resulted in a 6.7% decrement to the EIA data and the DENC estimate resulted in a 7.5% decrement to the EIA data. The average of the two estimates is 7.1%. Because the infrastructure cost estimates were very similar between the Companies and DENC, the Companies recommended using the average of the two estimates (7.1%) and rounding down the result to 7.0%. The Public Staff found this 7.0% decrement to the EIA data to be a reasonable adjustment to reflect the economies of scale associated with constructing four CT units at a greenfield site. In this Sub 194 proceeding, the Companies updated their economies of scale estimates which resulted in a

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[2] *See* U.S. Energy Information Administration, Cost and Performance Characteristic of New Generating Technologies, Annual Energy Outlook 2023, Table 2 at 5, *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.

[3] The Companies developed this methodology collaboratively with input from DENC in the E-100, Sub 175 avoided cost proceeding (the "2021 Sub 175 proceeding") and understand that DENC is using a consistent greenfield economies of scale methodology to develop their avoided CT capital cost.

[4] Burns & McDonnell is an internationally recognized engineering design firm providing engineering, architecture, construction, and consulting services. The Companies have used Burns & McDonnell for a number of years to provide technology cost and operating assumptions for use in the Companies' planning models.

[5] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 148 at 54 (Ordering Paragraph No. 6) (Oct. 11, 2017) (explaining that DEC, DEP, and DNCP shall recalculate the installed costs of a CT excluding economies of scope and taking into account any carrying costs associated with the economies of scale).

6.5% decrement to the EIA data. Given that the results were very similar to the 2021 Sub 175 proceeding findings, the Companies rounded up to 7.0% consistent with the methodology applied and approved in the 2021 Sub 175 proceeding. A 7.0% decrement to the EIA data results in an overnight capital cost of $872/kW (2022 dollars), which DEC and DEP are using to develop their avoided capacity rates in the Sub 194 docket.

CT Capital Cost with Economies of Scale Adjustments[6]

(2023 $MM unless otherwise noted)

EIA Cost Basis			**Comments**
Nominal Rating (MW)		237	EIA Annual Energy Outlook 2023, Table 1
Total Capital Cost (2022 $/kW)		793	EIA Annual Energy Outlook 2023, Table 2
Total Capital Cost (2023 $/kW)		938	Escalation to 2023$ based on Burns & McDonnell estimates
Total Capital Cost (2023$)		222	Reflects cost to construct a single unit at a greenfield site
Infrastructure Economies of Scale Adjustments			
Natural Gas M&R Station	$	4.2	Based on February 2020 EIA Capital Cost Report
Electrical Interconnect	$	0.8	Based on February 2020 EIA Capital Cost Report
Land acquisition	$	0.8	Based on February 2020 EIA Capital Cost Report
Civil	$	2.4	Based on internal estimates
Water: Muni. Tie and Demin. Tank	$	1.8	Based on internal estimates
Fire Header	$	3.3	Based on internal estimates
Admin Building/Security	$	5.1	Based on internal estimates
Subtotal	**$**	**18.3**	
Contingency (10%)	$	1.8	Based on February 2020 EIA Capital Cost Report
Total Common Infrastructure Cost	**$**	**20.1**	
Total Common Infrastructure Cost per Unit	$	5.0	
Common Infrastructure Cost Adjustment	**$**	**(15.1)**	
Total Adjusted Capital Cost excl Carry Cost ($)	**$**	**207.2**	Reflects economies of scale for constructing 4 CTs at a greenfield site
Total Adjusted Capital Cost excl Carry Cost ($/kW)	**$**	**874**	Reflects economies of scale for constructing 4 CTs at a greenfield site
Economies of Scale Carrying Cost Adjustment			
Carrying Cost Adj ($/kW)	$	3.2	
Total Adj Capital Cost incl Carry Cost Adj ($/kW)	**$**	**877**	Reflects economies of scale for constructing 4 CTs at a greenfield site incl carry cost adjustment
Calculated % Adjustment to EIA CT Cost		6.5%	
Modeled CT Cost			
EIA Total Capital Cost (2023 $/kW)	$	938	
Modeled % Adjustment		7.0%	
Total Adjusted Capital Cost (2023 $/kW)	**$**	**872**	

Source: EIA Cost and Performance Characteristics, March 2023
https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[6] U.S. Energy Info. Admin., EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook (Mar. 2023), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.

III. CT Fixed Operations and Maintenance Cost

To calculate the fixed operations and maintenance ("FOM") costs of a CT unit, the Companies use EIA FOM data for a single-unit greenfield site and apply Burns & McDonnell estimates to adjust the cost to reflect the economies for a four-unit CT site.[7] This calculation resulted in a FOM of $3.6/kW-Yr (2023 dollars) for use in this Sub 194 filing.

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EIA Single Unit Greenfield Site		
FOM ($/kW-Yr, 2022$)	7.88	EIA Annual Energy Outlook 2023, Table 1
FOM ($/kW-Yr, 2023$)	8.08	Assume 2.5% Inflation Rate
Capacity Rating (MW)	237	EIA Annual Energy Outlook 2023, Table 1
FOM (2023 MM$)	1.9	
Burns & McDonnell Estimates		
1st Unit (2023 MM$)	[redacted]	
Next Unit (2023 MM$)	[redacted]	
4 Unit Site (2023 MM$)	[redacted]	

	(2023 $/kW-Yr)	
	1 Unit	**4 Units**
EIA	8.1	3.6
Burns & McDonnell Estimates	[redacted]	[redacted]

EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023
https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

END CONFIDENTIAL

[7] *Id*. at 2 (Table 1).

IV. Avoided Capacity Rate Design

The Public Staff and the Companies agreed in the Commission-approved Sub 158 Rate Design Stipulation to utilize the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé 2018 Solar Capacity Value Study. Astrapé completed a new resource adequacy study in 2023, and the Companies have used the loss of load risk identified in this more recent study for updating the avoided capacity rate design in developing the current Sub 194 filing.[8]

DEC

Capacity Payment Period Definitions

The loss of load risk table below for DEC shows that loss of load risk occurs almost exclusively during the winter AM hours for the months of December-February with no loss of load risk occurring during summer PM hours. This is a change from the capacity payment periods defined in the prior 2021 Sub 175 proceeding, which relied on results from the 2020 Resource Adequacy Study. The 2021 Sub 175 proceeding definitions included March in the winter period and some PM hours in the summer. The updated 2023 Resource Adequacy Study has a greater amount of solar in the study year which shifts more loss of load risk from the summer to the winter and from daylight hours to non-daylight hours. The DEC capacity payment hours maintain the same winter AM hours that were included in 2021 Sub 175 proceeding and the new DEC capacity payment period has been redefined as shown below.

DEC Capacity Payment Period Definition

	Dec-Feb
AM	HE 6-10

Seasonal Allocation Factor

The loss of load risk table shows a seasonal allocation of 100% winter and 0% summer for DEC compared to the 96% winter and 4% summer allocation applied in the 2021 Sub 175 proceeding.

DEC Seasonal Allocation

Winter	Summer
100%	0%

[8] The 2023 Resource Adequacy Study was filed with the Commission as Attachment I to the 2023 CPIRP in Docket No. E-100, Sub 190.

DEC Loss of Load Risk (2023 Resource Adequacy Study, 22% Reserve Margin)

	Month											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
2	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
3	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
4	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
5	1.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%
6	8.4%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
7	15.5%	4.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%
8	18.5%	4.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
9	10.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%
10	8.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
11	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
12	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%
19	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.1%
20	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
21	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
22	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
23	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
24	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%
SUM	74.7%	9.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	15.3%

DEP

Capacity Payment Period Definitions

The loss of load risk table below for DEP shows that loss of load risk occurs almost exclusively during winter AM hours for the months of December-February. The DEP capacity payment hours include the same winter AM hours as applied in the 2021 Sub 175 proceeding but no longer include the month of March. The new capacity payment period definition is shown below.

DEP Capacity Payment Period Definition

	Dec-Feb
AM	HE 5-9

Seasonal Allocation Factor

The seasonal allocation for DEP continues to show that 100% of the loss of load risk occurs during the winter.

DEP Seasonal Allocation

Winter	Summer
100%	0%

DEP Loss of Load Risk (2023 Resource Adequacy Study, 22% Reserve Margin)

	Month											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	2.9%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	4.7%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
5	8.0%	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
6	10.6%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
7	11.4%	6.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%
8	10.6%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
9	7.4%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%
10	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
11	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
12	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
23	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
24	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
SUM	73.2%	17.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.6%

V. Performance Adjustment Factor ("PAF")

In the 2021 Sub 175 proceeding, the Companies, Public Staff, and DENC reached a consensus to adopt the Equivalent Unplanned Outage Factor ("EUOF") metric for developing the PAF. Similar to the Equivalent Unplanned Outage Rate ("EUOR") metric, which the Commission directed the Companies to consider, the EUOF metric includes the impact of maintenance outages which can also occur during peak demand periods and appropriately excludes planned outages from the calculation. The Companies compiled five years (2018-2022) of Generating Availability Data System ("GADS") data, calculated EUOF for the entire generation fleet (excluding Company-owned solar resources)[9] and included the months consistent with the capacity payment period definitions which include the months of December-February.

EUOF equals the sum of all Unplanned Outage Hours plus Equivalent Unplanned Derated Hours divided by Period Hours. "Unplanned" hours include forced and maintenance outage hours and "Equivalent Unplanned" hours include equivalent forced and equivalent maintenance outage hours. The system weighted EUOF ("WEUOF") is calculated using the following formula established by the North American Electric Reliability Corporation ("NERC"):[10]

Weighted Equivalent Unplanned Outage Factor – WEUOF

$$WEUOF = \frac{\Sigma\,[(UOH + EUDH) \times NMC]}{\Sigma\,(PH \times NMC)} \times 100\%$$

$$WEUOF = \frac{\Sigma\,[(MOH + FOH + EFDH + EMDH) \times NMC]}{\Sigma\,(PH \times NMC)} \times 100\%$$

Based upon these calculations and the agreed-upon methodology, DEC's WEUOF for the five-year period is approximately 4.8% resulting in a PAF of 1.05. Similarly, DEP's WEUOF is approximately 6.5% which results in a PAF of 1.07.

[9] Because solar generation is not part of the mandatory GADS reporting requirements at this time, the WEUOF calculation is based on the performance of the entire generation fleet excluding Company-owned solar resources. NERC designed a phased-in approach for reporting solar data in GADS with 100 MW and greater facilities to begin GADS reporting in 2024 and 20 MW or greater facilities to begin reporting in 2025. The Companies do not own any facilities of 100 MW or more but plan to implement a pilot reporting program sometime in 2024 to test report GADS data for some facilities. If GADS data was available and Company-owned solar resources were included in the calculation, it would likely have a negligible impact on the WEUOF or resulting PAF since total Company-owned solar is approximately 337 MW (combined for DEC and DEP) compared to total Company-owned generation of approximately 36,000 MW (combined for DEC and DEP). *See also* NERC GADS Solar Generation Data Reporting Instructions, *available at* nerc.com/pa/RAPA/PA/Section1600DataRequestsDL/2024_GADS_Solar_DRI.pdf (last visited Oct. 20, 2023)

[10] North American Electric Reliability Corporation, Generating Availability Data System: Data Reporting Instructions, Appendix F, at F-17-F-18 (Jan. 2021), *available at* https://www.nerc.com/comm/PC/Generating%20Availability%20Data%20System%20Working%20Gro1/Item%203b_%20Appendix_F%20-%20Equations%20Rev1.pdf (last visited Oct. 20, 2023).

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WEUOF

DEC	Jan	Feb	Dec	Annual	
2018	[redacted]				
2019					
2020					
2021					
2022					PAF = 1/(1-WEUOF)
Average 2018-2022				4.8%	1.05

WEUOF

DEP	Jan	Feb	Dec	Annual	
2018	[redacted]				
2019					
2020					
2021					
2022					PAF = 1/(1-WEUOF)
Average 2018-2022				6.5%	1.07

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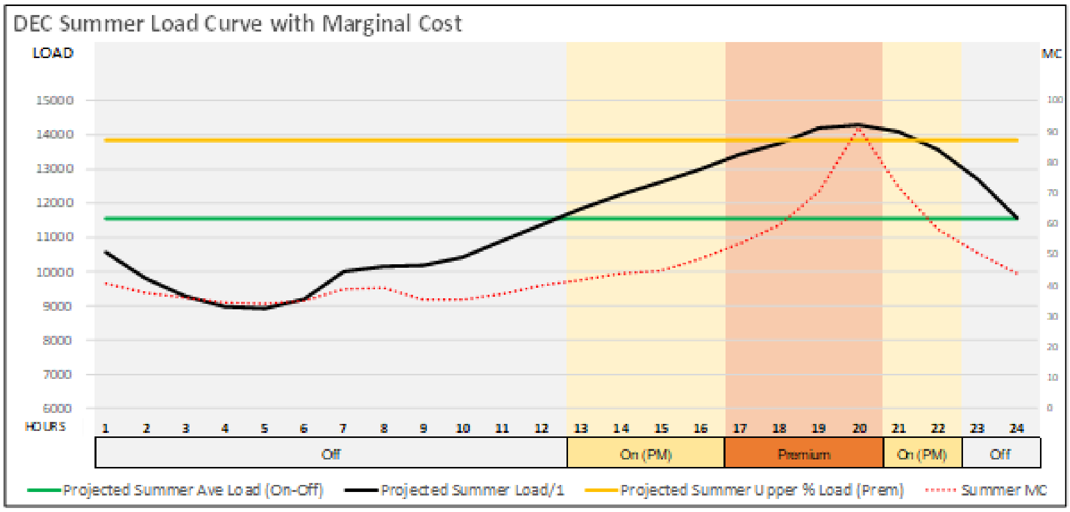
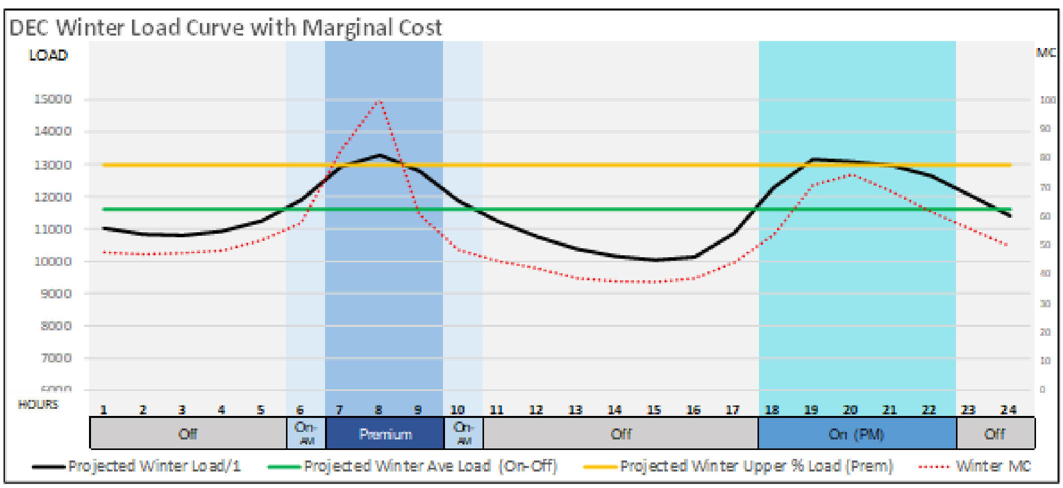
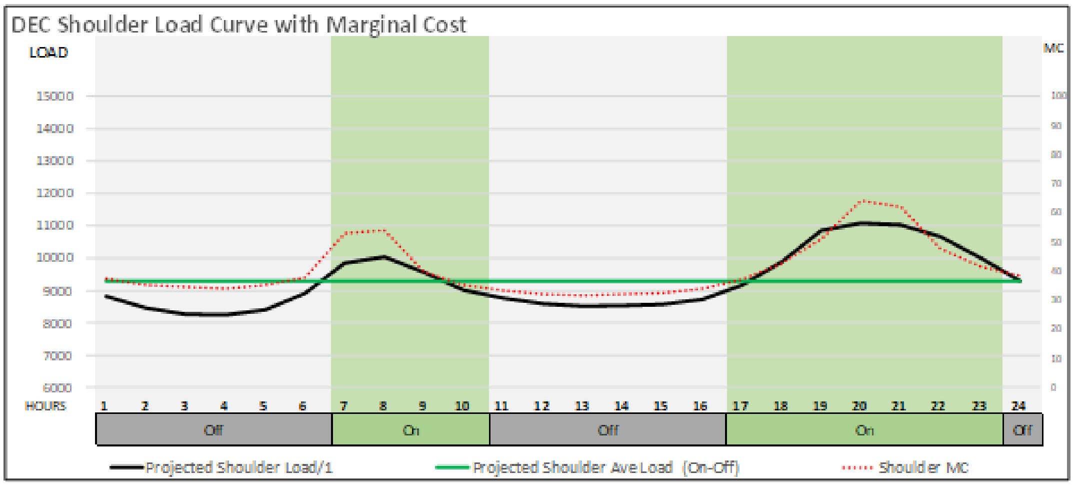
VI. Avoided Energy Rate Design

The following graphs are intended to provide a visual comparison of on-peak and premium peak hours by season based on DEC's and DEP's projected net loads and marginal costs as compared to currently approved Schedule PP energy price periods. The legend shows color-shaded blocks which represent the current energy period definitions and color-coded graph lines which show the projected hourly load net of renewable energy supply and a secondary layer showing the curve of marginal costs in the same hours. The hours where the net loads (black line) are above the season average (green line) are considered as potential on-peak or premium peak hours, and those above the upper-percentile level (gold line) guide the selection of the premium peak hours. The dotted red line represents the shape of the average marginal costs for further insight.

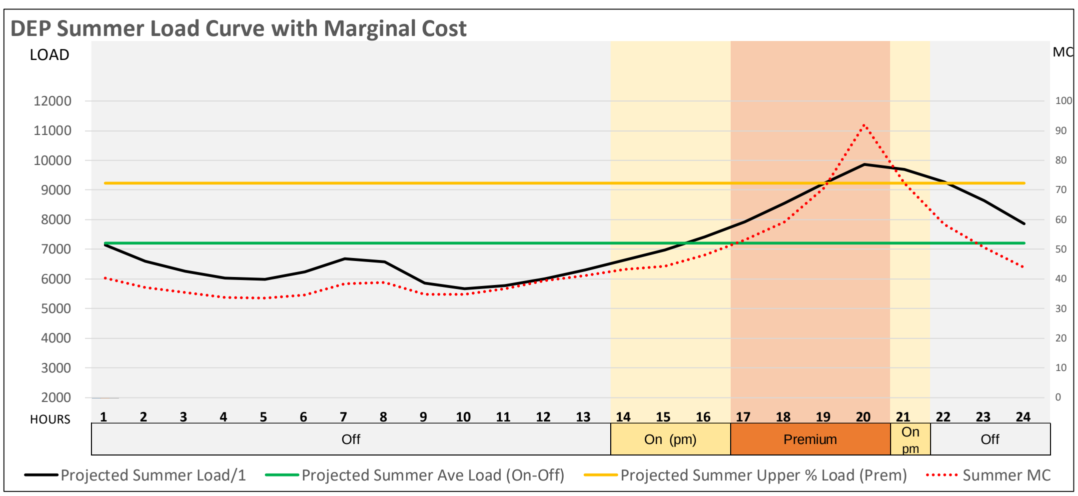
DEC Energy Rate Design Periods

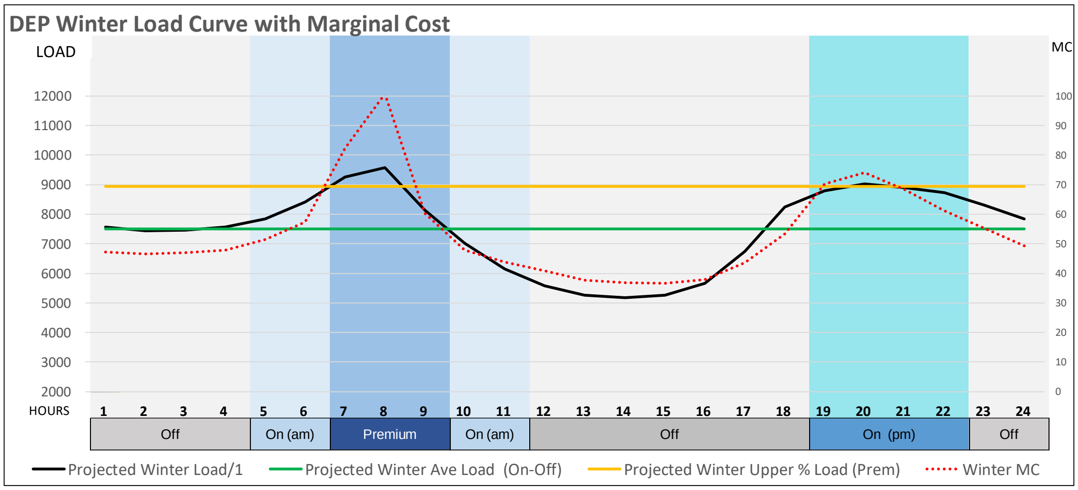


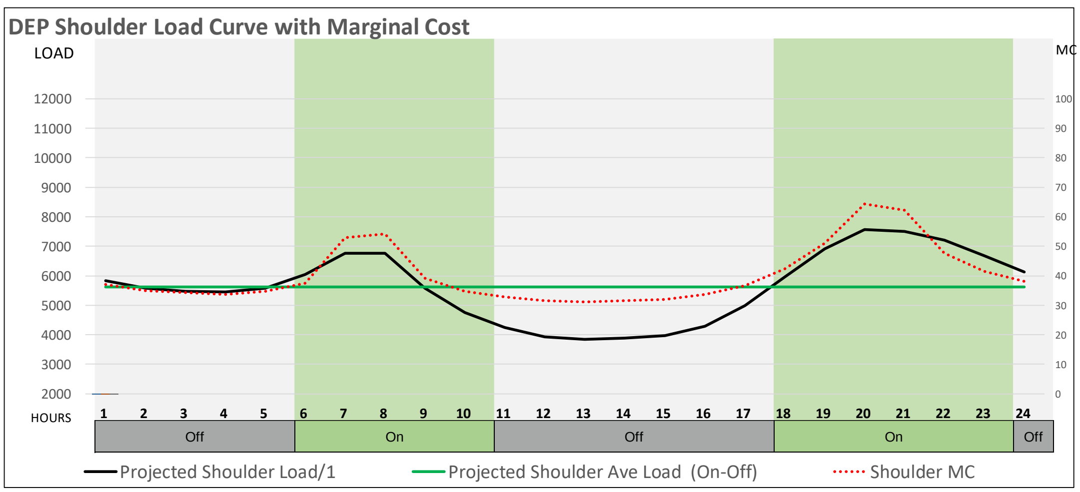




DEP Energy Rate Design Periods







Based on this review of the continued appropriateness of the rate design periods using net load and marginal cost information, the seasonal graphs above indicate adjustments to certain price block hourly definitions for both DEC and DEP are reasonable for the 2023 filing. The comparison charts below show the changes to the following price blocks between the 2023 proposed pricing periods and the 2021 pricing periods:

- DEC and DEP Summer Premium Peak
- DEC and DEP Summer On-Peak
- DEP Winter AM On-Peak
- DEC and DEP Winter PM On-Peak
- DEP Shoulder On-Peak

VII. DEC and DEP Avoided Energy and Capacity Pricing Periods

As compared to the pricing periods approved by the Commission in the 2021 Sub 175 proceeding, the Companies' 2023 proposed energy price blocks reflect adjustments to the hourly designations for DEC's summer and winter seasons and DEP's summer, winter, and shoulder seasons, however the months included in each energy season and the number of distinct price blocks (9) has not changed.

DEC Energy Pricing Periods (2023 to 2021 Comparison)

<table>
<tr><th colspan="25">DEC Energy Independent Price Blocks (2023)</th></tr>
<tr><td></td><td colspan="3">Summer Premium Peak</td><td colspan="3">Summer On-Peak</td><td colspan="2">Summer Off-Peak</td><td colspan="3">Winter Premium Peak</td><td colspan="3">Winter On-Peak (AM)</td><td colspan="3">Winter On-Peak (PM)</td><td colspan="2">Winter Off-Peak</td><td colspan="3">Shoulder On-Peak</td><td colspan="2">Shoulder Off-Peak</td></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jun - Sep)</td><td colspan="12">Off</td><td colspan="5">On</td><td colspan="4">Premium</td><td colspan="2">On</td><td>Off</td></tr>
<tr><td>Winter (Dec - Feb)</td><td colspan="5">Off</td><td>On</td><td colspan="3">Premium</td><td>On</td><td colspan="7">Off</td><td colspan="6">On (PM)</td><td>Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="6">Off</td><td colspan="4">On</td><td colspan="6">Off</td><td colspan="7">On</td><td>Off</td></tr>
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</table>

DEP Energy Pricing Periods (2023 to 2021 Comparison)

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<tr><th colspan="25">DEP Energy Independent Price Blocks (2021)</th></tr>
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<tr><td>Shoulder (Remaining)</td><td colspan="5">Off</td><td colspan="5">On</td><td colspan="7">Off</td><td colspan="6">On</td><td>Off</td></tr>
</table>

The Companies' 2023 proposed capacity price blocks reflect the discontinuation of the DEC summer season. There are no changes to the hourly designations for DEC or DEP's winter season, however March is no longer included as a winter season month for either Company.

DEC Capacity Pricing Periods (2023 to 2021 Comparison)

<table>
<tr><th colspan="25">DEC Capacity Independent Price Blocks (2023)</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
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</table>

<table>
<tr><th colspan="25">DEC Capacity Independent Price Blocks (2021)</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jul - Aug)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="4">Summer</td><td></td><td></td><td></td></tr>
<tr><td>Winter (Dec - Mar)</td><td></td><td></td><td></td><td></td><td></td><td colspan="5">Winter</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

DEP Capacity Pricing Periods (2023 to 2021) Comparison

DEP Capacity Independent Price Blocks (2023)																								
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter (Dec - Feb)					Winter																			

DEP Capacity Independent Price Blocks (2021)																								
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter (Dec - Mar)					Winter																			

VIII. Avoided Fuel Hedge Value

For purposes of calculating avoided energy rates in this proceeding, and consistent with prior proceedings and the Public Staff's recommendation,[11] the Companies have used the Black-Scholes option pricing model to determine the fuel hedging benefits. Consistent with this approach, the Companies entered the current Henry Hub gas pricing data into the option pricing model, resulting in a call option value of approximately $0.5526/MMBtu and a put option value of $0.4386/MMBtu. The net option price, or difference between the call and put option values, of $0.1140/MMBtu represents the estimated fuel price hedging benefit. Multiplying the $0.1140/MMBtu by a gas combined-cycle plant heat rate of 7 MMBtu/MWh results in a fuel price hedging value of $0.80/MWh, which is assumed constant for all years of the Schedule PP contract. The primary driver for the increase in the avoided fuel hedge value from $0.02/MWh in Sub 175 to $0.80/MWh in Sub 194 is higher interest rates. The Black-Sholes Model inputs and results are shown below.

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Fuel Hedge Value - Black-Scholes Model

As of Date: 10/12/2023

Forward Month	NYMEX Henry Hub Gas[1]	Gas Vol[2]	Interest Rate[2]	Expiry[3]	Time to Expiry	Call Option[4]	Put Option[4]	Call-Put Spread	Assumed Gas Heat Rate[5]	Hedge Value ($/MWh)
Jun-24	3.403	[redacted]		5/28/2024	0.6274	$ 0.5526	$ 0.4386	$ 0.1140	7	$ 0.80

Assumptions:

[1]Nymex Henry Hub Gas price sourced from NYMEX as of 10/12/23 for June 2024 contract

[2]Gas volatility curve and interest rate curve as of 10/12/23 for June 2024 contract sourced from internal and confidential CXL database used as a source of record for commodities, and trading positions

[3]Assumed June 2024 contract expires 3 days before the end of the month

[4]Call and put options valuated via Black Scholes calculator (European option)

[5]Assumed average combined cycle gas heat rate of 7 MMBtu/MWh

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[11] *See* Initial Statement of the Public Staff, Docket No. E-100, Sub 140 at 36 (filed June 22, 2015).

IX. Distributing Avoided Energy Cost to the Proposed Avoided Energy Rate Design

Projected avoided production costs are determined as the difference between a base case and a proxy 100 MW no-cost QF purchase case for each of the Companies.

To ensure yearly consistency of the relationship among the rate periods, avoided energy cost are distributed to the proposed rate periods using the hourly marginal cost as a guide as follows:

- The hourly marginal cost from the avoided cost base case is filtered to remove penalty prices that are not reflective of projected production costs.
- The avoided energy cost from the production cost cases will be averaged by year for each company. The annual average of the filtered marginal costs from the avoided cost base case will also be calculated. Then, the ratio of average avoided energy cost to average marginal cost will be determined.
- The annual ratio will be applied to the hourly marginal cost of each company which will become the hourly avoided energy cost.
- The hourly avoided energy costs will be grouped into the proposed rate periods.

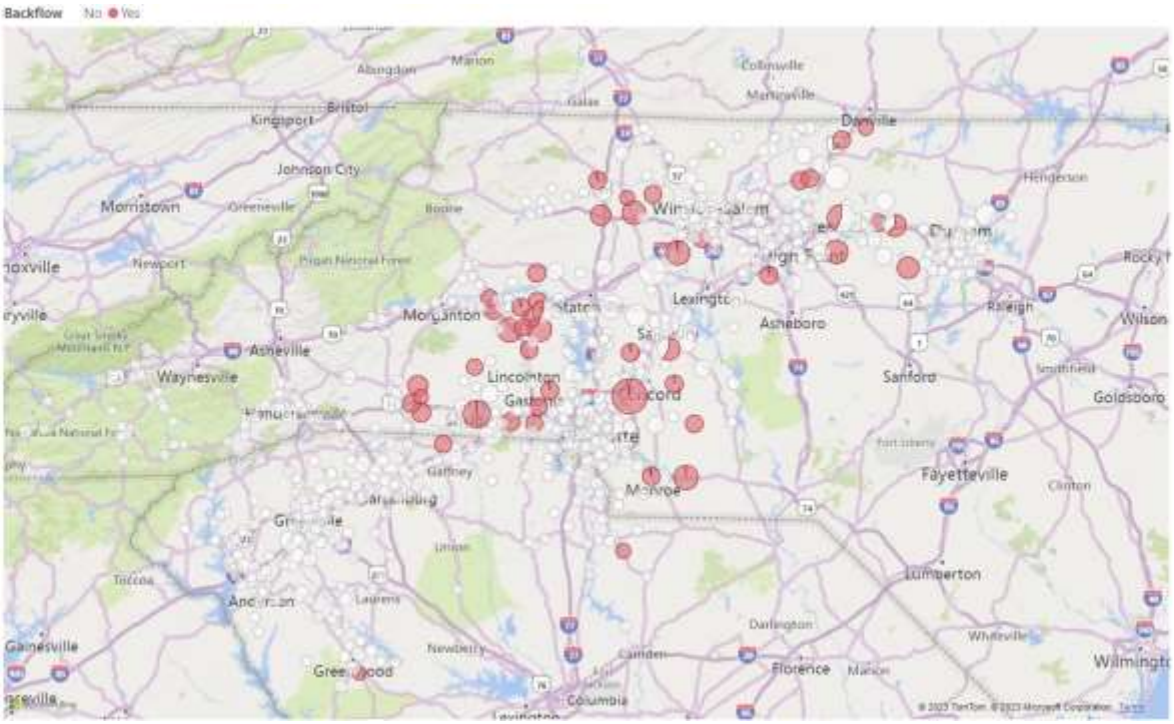
DEC / DEP Exhibit 9

Geographical Location of Substations with Backflow in North and South Carolina

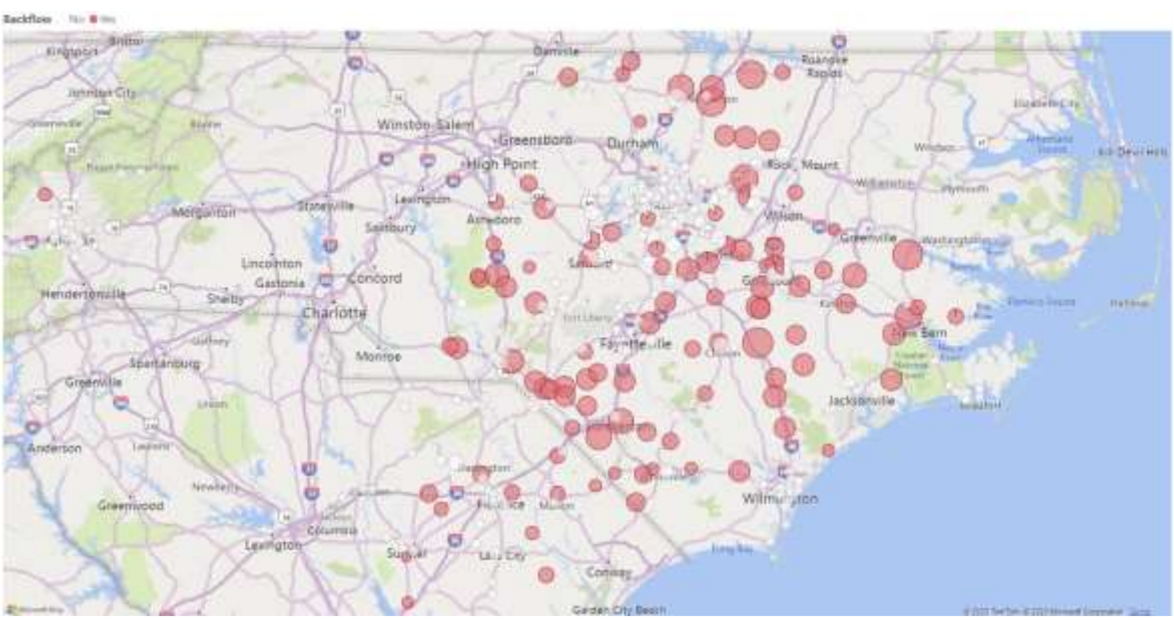
Docket No. E-100, Sub 194

NC Avoided Cost Filing (Docket No. E-100, Sub 194)
DEC/DEP Joint Exhibit 9
Geographical Locations of Substations with Backflow in North and South Carolina

I. DEC Substation Banks with Backflow due to Distributed Energy Resources (“DER”) (bubble size indicates the megawatts (“MW”) of capacity of DER at each site).



II. DEP Substation Banks with Backflow due to DER (bubble size indicates the MW of capacity of DER at each site).



DEC / DEP Exhibit 10

2023 Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge Study, prepared by Astrapé Consulting

Docket No. E-100, Sub 194

Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study

11/1/2023

PREPARED FOR

Duke Energy

PREPARED BY

Astrapé Consulting
Nick Wintermantel
Kevin Carden
Parth Patel
Cole Benson

Contents

Executive Summary

The Solar Integration Service Charge ("SISC") Study is the third SISC Study ("Study" or "2023 Study") performed by Astrapé Consulting for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP" and together with DEC, the "Companies"), referred to herein as the Companies. The first study was conducted in 2018 and the second study was conducted in 2021 ("the 2021 study"). As part of the second 2021 study, the Companies, with input from the North Carolina Public Staff ("NCPS") and South Carolina Office of Regulatory Staff ("ORS"), retained The Brattle Group ("Brattle") as Technical Review Committee ("TRC") Principal consultant. Brattle coordinated TRC meetings to review the findings of the 2021 Study and separately authored a TRC report for the Companies to incorporate in their 2021 regulatory filings. In addition to Brattle, the TRC consisted of regulatory observers from the NCPS, ORS, and technical leads from three national labs. The TRC provided significant feedback and recommendations during a bi-weekly review process which commenced in March 2021 and concluded in July 2021. These recommendations were reflected in the 2021 study and now in the 2023 Study which is discussed throughout this report.

As DEC and DEP continue to add solar to their systems, understanding the impact the solar fleet has on real time operations is important. Due to the intermittent nature of solar resources and the requirement to meet real time load on a minute-to-minute basis, online dispatchable resources need to have enough flexibility to ramp up and down to accommodate unexpected movements in solar output. Not only can solar drop off quickly, but it can also ramp up quickly. Unexpected movement in either direction causes system ramping needs. When solar output drops off quickly, reliability can be an issue if other generators are not able to ramp up fast enough to replace the lost solar energy. When solar ramps up quickly, if other generators are not able to ramp down to match the solar output change, some solar generation may need to be curtailed. At low solar penetrations, the unexpected changes in solar output can be cost effectively accommodated by increasing upward ancillary service[1] targets within the existing conventional fleet. Increasing ancillary service targets forces the system to commit more generating resources which allows generators to dispatch at lower levels giving them more capability to ramp up. There is a cost to this increase in ancillary services because generators are operated less efficiently when they are dispatched at lower levels. Generators may also start more frequently, which also increases costs. As solar penetrations continue to rise, carrying additional ancillary services to mitigate solar uncertainty with the conventional fleet becomes more expensive. This 2023 Study analyzes multiple solar penetration levels and quantifies the cost of utilizing the existing fleet to reliably integrate the additional solar generation.

For this Study, the Strategic Energy and Risk Valuation Model ("SERVM") was utilized because it not only performs intra-hour simulations which include full commitment and dispatch logic, but also because its commitment and dispatch decisions can be performed against uncertain net load forecasts. This uncertainty results in flexibility excursions defined as an event where the online generation fleet is not able to ramp fast enough to match upward net load perturbations. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. At each solar penetration level, simulations were performed assuming the same ancillary service inputs that are used in SERVM simulations with zero solar capacity. The number of flexibility excursions were recorded from those simulations. Next, total flexibility excursions with solar generation were calibrated to the same level as in the zero solar simulations by increasing ancillary services in the form of load following reserves. The goal of the Study is to maintain the same ability to follow net load as demonstrated in the no solar base case in any solar

[1] Ancillary services are defined in further detail in the Model Inputs and Setup Section of the Study, but for purposes of this Study, load following, which is represented by 10-minute system ramping capability, was used to resolve flexibility gaps.

penetration level analyzed. Finally, system costs were compared between operating with the zero-solar baseline ancillary services (lower cost, but more flexibility excursions) to operating with the higher-solar load following requirements (higher cost but achieves the same level of flexibility excursions that existed before the solar was added). The difference in cost is allocated to the solar energy and represents the Solar Integration Service Charge (SISC). The SISC was estimated for both an "island case," which assumes DEC and DEP need to follow their respective loads with their own resources and a "combined case", which approximates the joint dispatch agreement under which DEC and DEP are currently operating as recommended by the TRC.

Two levels of solar penetration were modeled for both DEC and DEP as shown in Table ES-1. The solar penetration scenarios reflect a range of solar capacity that would cover the Companies' expectations over the next 10 years consistent with the 2027 Study year. Calculating the SISC for these levels provides the Companies with a SISC value as a function of solar penetration to be used in setting the SISC. The Appendix includes a third (even higher) tranche of solar generation which was simulated but is not relevant to the current effort of setting the SISC due to solar capacity levels modeled that exceed the levels DEC and DEP will reach in the next several years.

Table ES-1. DEC and DEP Solar Penetrations Analyzed

	DEC MW	DEP MW	Total MW
Tranche 1	1,873	3,590	5,463
Tranche 2	2,738	4,392	7,130

Tables ES-2 and ES-3 show the results of the island cases for both DEC and DEP which were used to determine the load following requirements for each Company. As solar generation is added, net load volatility increases, causing flexibility excursions to increase. To reduce the excursions, additional load following is added across the day, which is discussed in detail later in the report. SERVM then commits to the higher load following target which causes an increase in costs. For DEC, Table ES-2 shows that as solar increases from 0 MW to 1,873 MW, on average 16 MW of additional load following across the daytime hours is required to maintain the same number of excursions that occurred in the 0 MW solar scenario. When tranche 2 is added to the analysis, which includes 2,738 MW, 26 MW of additional load following on average across daytime hours is required compared to the 0 MW solar case. Similar patterns are seen in DEP, as shown in Table ES-3. Tranche 1, which assumes 3,590 MW of solar capacity, requires 49 MW of additional load following on average across daytime hours. Tranche 2, which assumes 4,392 MW of solar capacity, requires 65 MW of additional load following on average across daytime hours.

Table ES-2. DEC Island Results

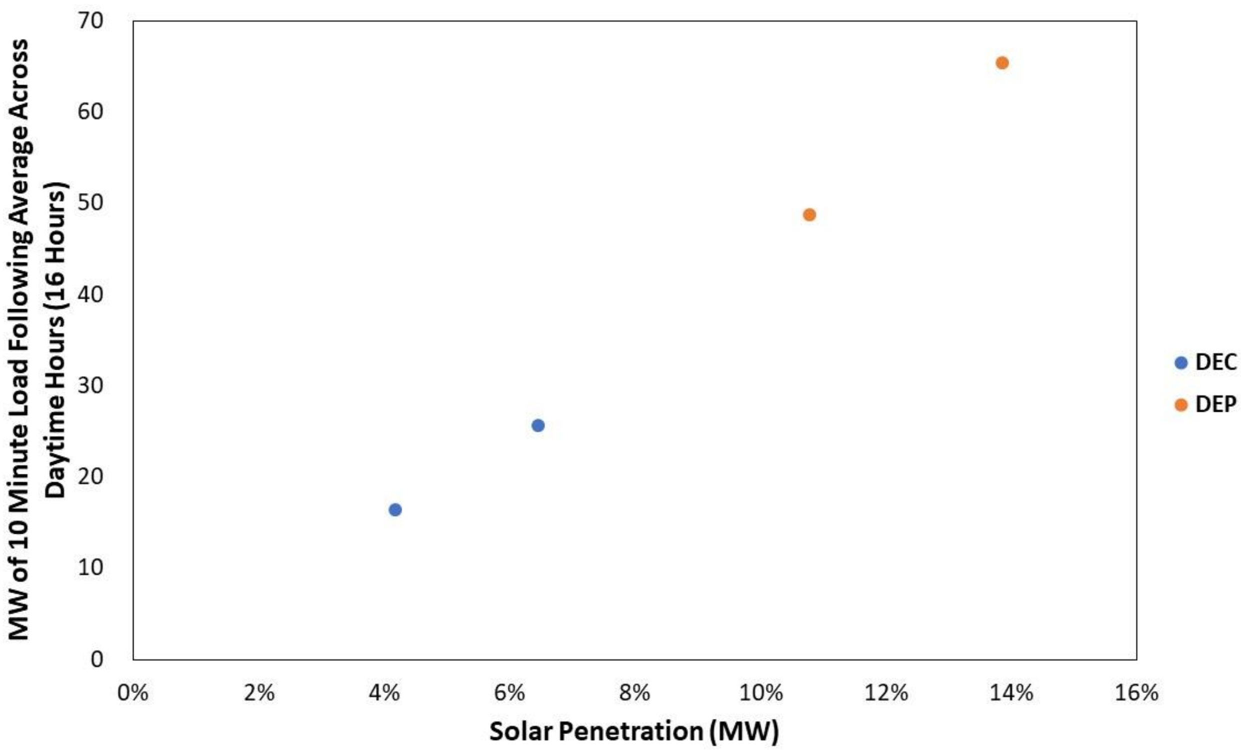
	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	1,873	2,738
Flexibility Violations (Events Per Year)	2.94	2.94	2.94
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	16	26

Table ES-3. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	3,590	4,392
Flexibility Violations (Events Per Year)	1.47	1.47	1.47
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	49	65

Figure ES-1 shows the load following increase as a function of solar penetration for both DEC and DEP.

Figure ES-1. Quantified Required Increase in Load Following Reserves as a Percentage of Solar Penetration



As requested by the TRC in the 2021 Study, the Study simulated the Joint Dispatch Agreement (JDA) between the DEC and DEP balancing areas to determine the SISC.[2] The combined JDA results reflect modeling the DEC and DEP balancing areas simultaneously with unlimited transmission capability between them similar to the 2023 Resource Adequacy Study.

In these simulations, the realized load following additions determined in the island case with separate balancing areas were targeted for the combined case except now economic transfers can be made on a

[2] The island SISC costs were also calculated and are shown in the body of the Study report.

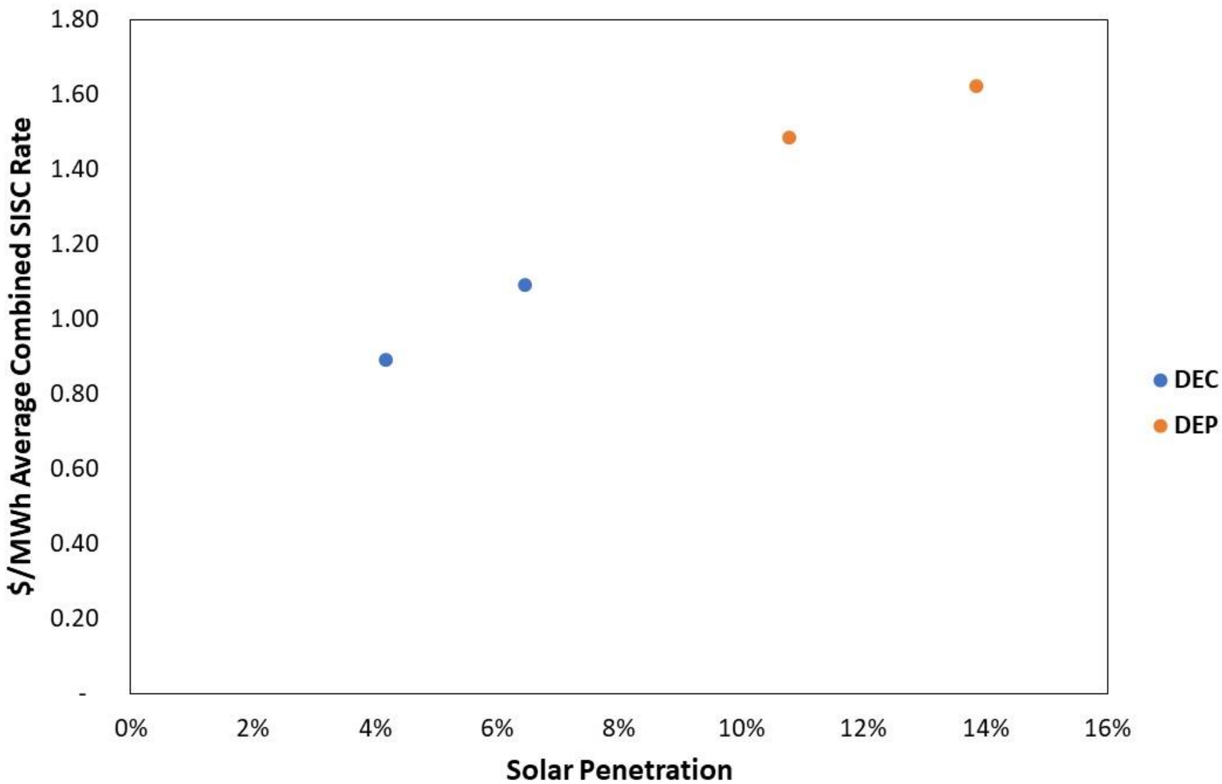
5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility. The results are shown in the following table. As expected, there are total savings versus the island scenario as discussed in the body of the report. These benefits then have to be allocated to each Companies' integration cost. Astrapé, along with the TRC and the Companies, determined in the 2021 Study it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis compared to the island results, which has also been applied in the updated 2023 Study. Table ES-4 shows the load following cost rate as well as the average and incremental SISC rates based on the JDA simulations. The average SISC rate represents the integration cost charge for the entire tranche of solar while the incremental SISC rate represents the integration cost charge only for the incremental level of solar between Tranche 1 and Tranche 2. The load following cost rate is the total production cost increase divided by the additional 10-minute load following reserves that are increased.

Table ES-4. Combined Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	1,873	3,590	5,463	2,738	4,392	7,130
Solar Generation (MWh)	4,209,236	7,498,434	11,707,670	6,496,508	9,627,651	16,124,160
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	39.24	39.24	39.24	42.82	42.82	42.82
Average SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.09	1.62	1.41
Incremental SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.46	2.11	1.77

Figure ES-2 shows the average SISC for both tranches by Company for the combined cases.

Figure ES-2. Average Combined SISC Rates for Tranche 1 and 2



These SISC average and incremental rates across these tranches provide the Companies with information to determine a rate to be used in its avoided cost filing. There are average and incremental rates across a wide range of solar penetrations. The rates are highly correlated with the solar penetration as seen in Figure ES-2 so SISC rates for any penetration level can be deduced from the analysis.

Key Drivers of Change from the 2021 Study

There were a number of key changes to the systems modeled in the 2023 Study compared to the 2021 Study that drive changes in results. The first is the increase in gas prices compared to the 2021 Study. Since the 2021 study, the gas prices modeled have increased substantially which increases the costs of incremental load following and thus the SISC. However, this increase in gas price is offset by the addition of flexible resources. In the 2021 Study, there was approximately 180 MW of battery storage across the DEC and DEP systems. This has increased to approximately 700 MW of battery storage in the 2023 Study. The DEC system also added Lincoln 17, which is a flexible CT. Finally, Astrapé and the Companies incorporated feedback from the TRC regarding the 2021 Study and have incorporated the Southeastern Energy Exchange Market (SEEM) into the 2023 Study. These improvements to system flexibility decreased the incremental need for load following and despite the cost increase of incremental load following caused by gas prices, there is a net decrease in the SISC compared to the 2021 Study as a function of solar penetration.

The following sections of this report provide greater detail regarding the SISC study framework, model inputs, simulation methodology, and study results.

I. Study Framework

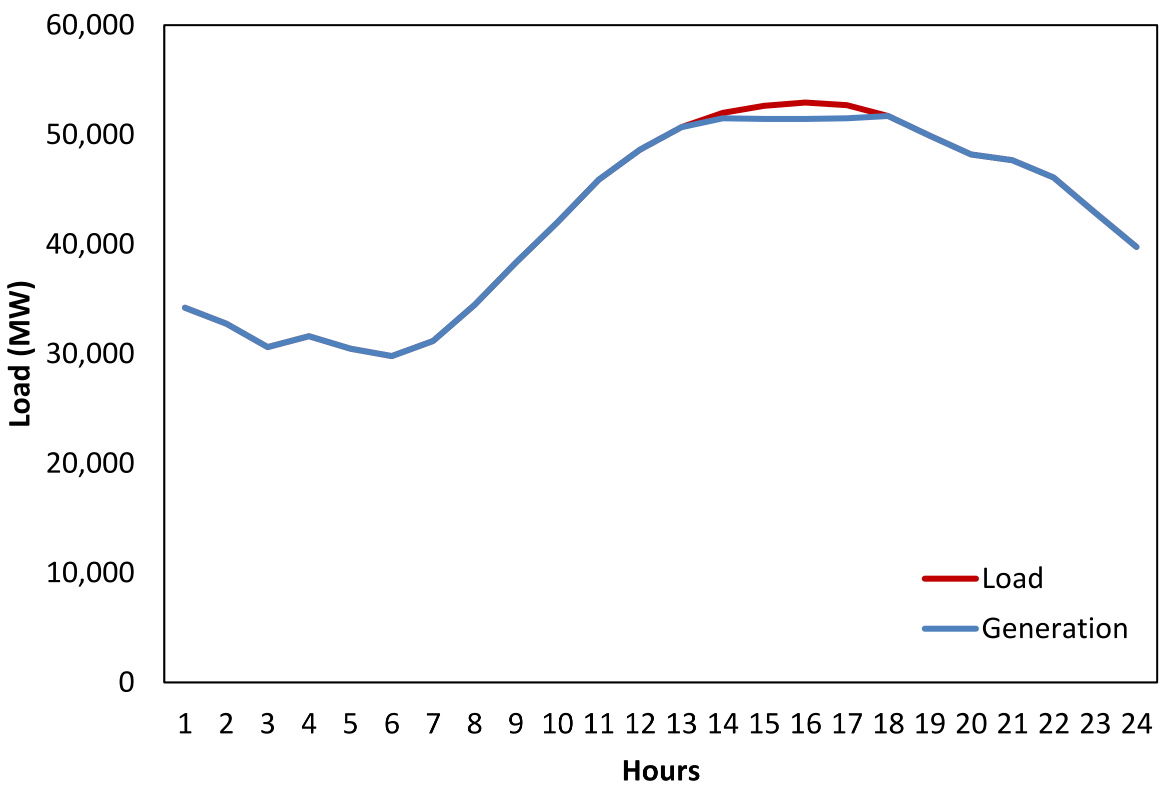
The economic effects of adding significant solar generation to a fleet are generally analyzed in a production cost simulation model. These models perform a commitment and dispatch of the conventional fleet against the gross load minus the expected renewable generation. Comparing the economic results from simulations with significant solar against simulations with more conventional resources allows planners to assess the economic implications of these additions. However, these analyses typically commit and dispatch resources with an exact representation of the load and solar patterns. This perfect knowledge aspect of the simulations overstates the value of resources like solar because they have significant inherent uncertainty. This Study incorporates the inherent uncertainty and forces the production cost model to make decisions without perfect knowledge of the load, solar, or conventional generator availability. In this framework, the objective function of the commitment and dispatch is still to minimize cost.

The enforcement of reliability requirements in simulation tools with perfect foresight is generally through a reserve margin constraint. Each year is required to have adequate capacity to meet a particular reserve margin requirement. These types of simulations are unlikely to recognize reliability events partly because of their perfect foresight framework, but also because they use simplified generator outage logic. The outages at any discrete hour in the simulations typically represent average outages. In actual practice, reliability events are driven by coincident generator outages much larger in magnitude than the average. In the simulations performed for this Study, the SERVM model incorporates both load and solar uncertainty, as well as generator outage variability. In this framework, testing the capability of the conventional fleet to integrate solar resources is more reflective of actual conditions.

The inability to match generation and net load driven by solar output variability and volatility is different from capacity shortfall events analyzed in a typical resource adequacy analysis. They are events that could have been addressed by operating the existing conventional fleet differently. If solar output in a hypothetical system were to drop unexpectedly by 1,000 MW in a 5-minute period, only resources that are online or synched to the grid with the appropriate operating flexibility would be able to help alleviate the loss of the solar energy. So, for this analysis, the model differentiates events by their cause. Inputs are optimized such that events driven by a lack of capacity and events driven by a lack of flexibility achieve specific targets at minimum cost.

(1) Loss of Load Expectation (LOLE): number of days per year with loss of load due to capacity shortages. Figure 1 shows an example of a capacity shortfall which typically occurs across the peak of a day.

Figure 1. LOLE Example



(2) Flexibility Excursions: number of days per year the system cannot meet a known 5-minute net load ramp due to system flexibility shortfalls. In other words, there was enough capacity installed but not

enough flexibility to meet the net load ramps, or startup times prevented a unit from coming online fast enough to meet the unanticipated ramps. The vast majority of the flexibility excursions occur in less than one hour.

Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is "one day in 10 years" LOLE, or 0.1 LOLE. To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period. Reliability targets for operational reliability are covered by the North American Electric Reliability Corporation ("NERC") Balancing Standards. The Control Performance Standards (CPS) dictate the responsibilities for Balancing Areas (BA) to maintain frequency targets by matching generation and load.

Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and the Balancing Authority Area Control Error Limit (BAAL) would be ideal. However, simulating violations of these standards is not possible. While the simulations performed in SERVM do not measure the NERC Balancing Standards, the flexibility excursions (times when a 5-minute known net load could not be met by the system's generation fleet) are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. Any periods in which generation is not able to meet load but there is sufficient installed capacity on the system are recorded as flexibility excursions. While there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, there is not a standard for flexibility excursions as measured by SERVM or in other solar integration modeling practices. Absent a standard, this Study assumes that maintaining the same level of flexibility excursions as solar penetration increases is an appropriate objective. The DEC and DEP systems were simulated with current loads and resources until operating reserves in the no solar case were similar to historical operating reserves. Running the system like this produces a number of flexibility excursions which would become the target that would be maintained after solar is added.

For each renewable penetration level analyzed, changes were made to the level of load following targeted to maintain the same number of flexibility excursions per year as seen in the base case with no solar. With more ramping capability provided by the increase in load following reserves, the unexpected drops in solar output are not as likely to create flexibility excursions. However, this creates a change in operating costs that has an impact on system costs. Comparing the total production costs assuming the same ancillary services targets used before the solar was added to the final, mitigated case production costs calculated using higher load following targets, which brings flexibility excursions back to the same level as the no solar case, determines the SISC on the system.

The more solar resources that are added, the more challenging and more expensive it becomes to carry the necessary additional ancillary services. In some hours, all conventional generation resources are dispatched near their minimum generation level in order to provide the targeted operating reserves, and yet the total generation is still above the load. This situation results in solar curtailment. The model assumes that any overgeneration can be used as load following and since incremental overgeneration is correlated with incremental solar penetration, higher curtailment is actually associated with lower SISC in this Study. Given existing solar contracts, this treatment is potentially optimistic in that curtailment may not be able to be used as flexibly as typical load following capability, and the real-world system may be committed and dispatched less optimally to avoid some curtailment that is shown in the model results.

II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the SISC Study. The vast majority of inputs are consistent with 2023 Resource Adequacy Study completed for DEC and DEP. The model was simulated on 5-minute time intervals versus hourly intervals to capture the flexibility requirements of the system given imperfect knowledge around load, solar, and generating units. Simulating at 5-minute intervals requires additional information on generating resources and volatility distributions on load and solar as discussed in the following sections.

The utilities initially are modeled as islands for the SISC Study because each balancing area is responsible for its own NERC Compliance. However, given the joint dispatch agreements in place, DEC and DEP are dispatched as combined systems, which is discussed later in the combined JDA results. For resource adequacy, neighbor assistance capacity plays a significant role in the results. Weather diversity and generator outage diversity are benefits available to DEC and DEP regardless of the type of capacity neighboring regions build. Also, it is required to capture this assistance to achieve the one day in ten-year standard which equates to an LOLE of 0.1 events per year as outlined in the 2023 Resource Adequacy Study. To achieve approximately 0.1 LOLE in this study, additional resources at dispatch costs above a gas CT were included in both DEC and DEP systems to mimic outside purchases.

A. Load Forecasts and Load Shapes

Load Forecasts and Shape Modeling

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs for 2027 for both DEC and DEP which is in line with the 2023 Resource Adequacy Study.

Table 1. 2027 Peak Load Forecast

	DEC	DEP East	DEP West	Coincident DEP	Coincident System
Summer	18,848 MW	12,773 MW	884 MW	13,612 MW	32,298 MW
Winter	18,165 MW	13,778 MW	1,197 MW	14,932 MW	32,765 MW

To model the effects of weather uncertainty, forty-three historical weather years (1980 - 2022) were developed to reflect the impact of weather on load. Based on recent historical weather and load[3], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from five weather stations across the DEC and DEP service territory. The weather stations included Charlotte, NC, Greensboro, NC, Greenville, NC, Raleigh, NC, Wilmington, NC, Fayetteville, NC, Asheville, NC, and Columbia, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last forty-three years of weather to develop forty-three synthetic load shapes for 2027. Equal probabilities were given to each of the forty-three load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2027.

Figures 2 to 7 below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for DEC, DEP-E, and DEP-W. The y-axis represents the percentage deviation from the average peak. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the

[3] The historical load included January 2014 through September 2019.

variance for winter is much greater than summer. As an example, and as seen in recent history, extreme cold temperatures can cause load to spike from additional electric strip heating and other heating sources. The highest summer temperatures typically are only a few degrees above the weather normal peak temperature and therefore do not produce as much peak load variation.

Figure 2. DEC Summer Peak Weather Variability

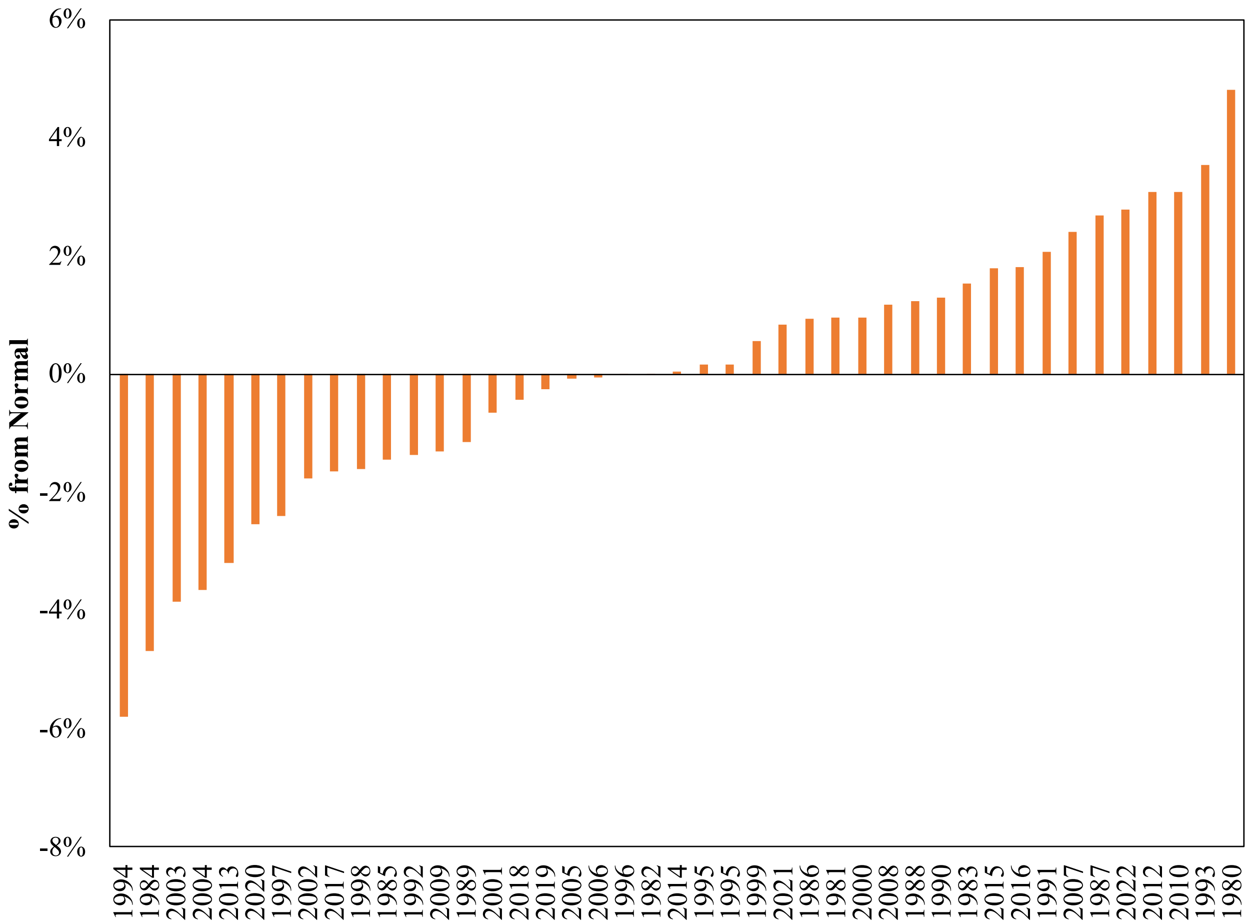


Figure 3. DEC Winter Peak Weather Variability

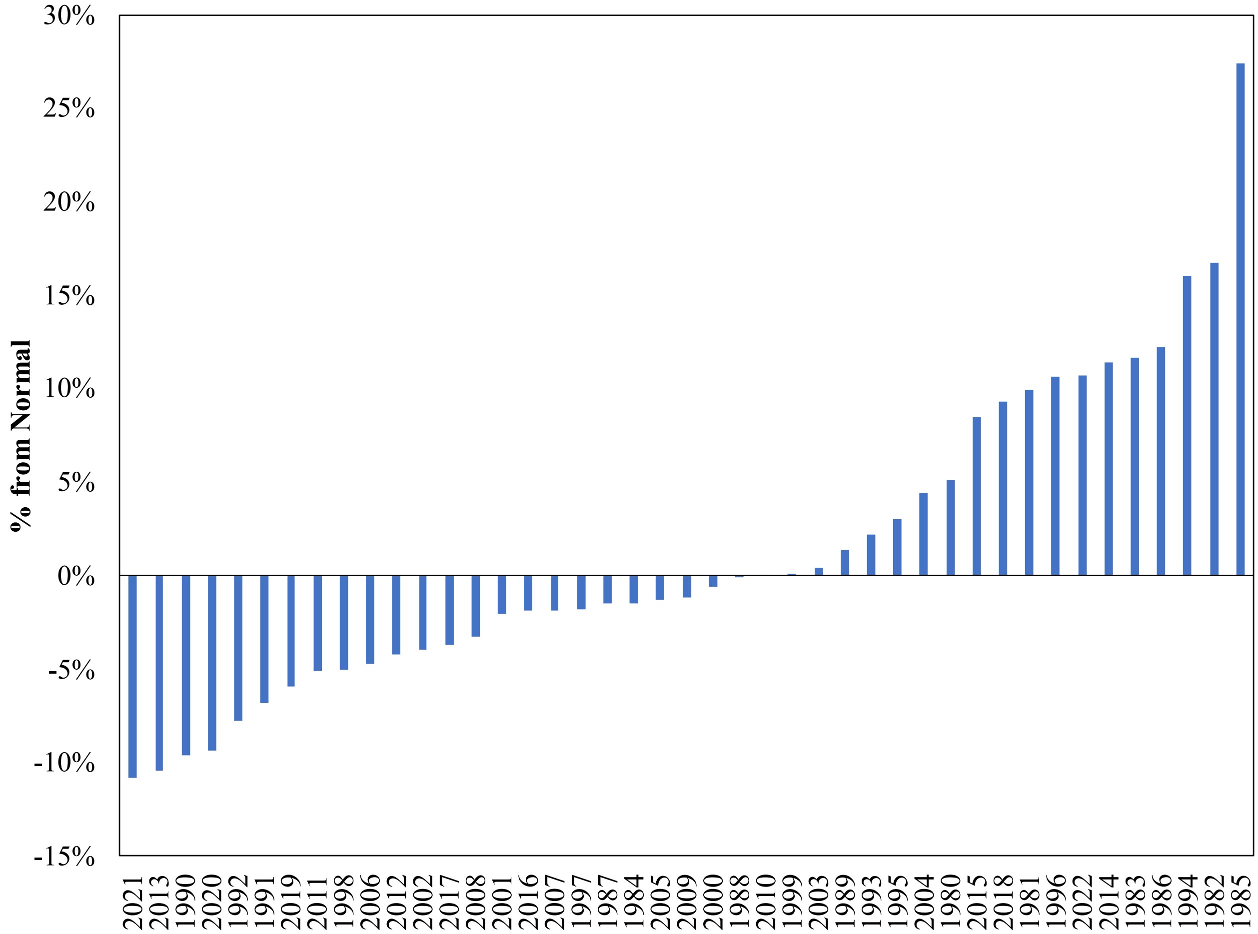


Figure 4. DEP-E Summer Peak Weather Variability

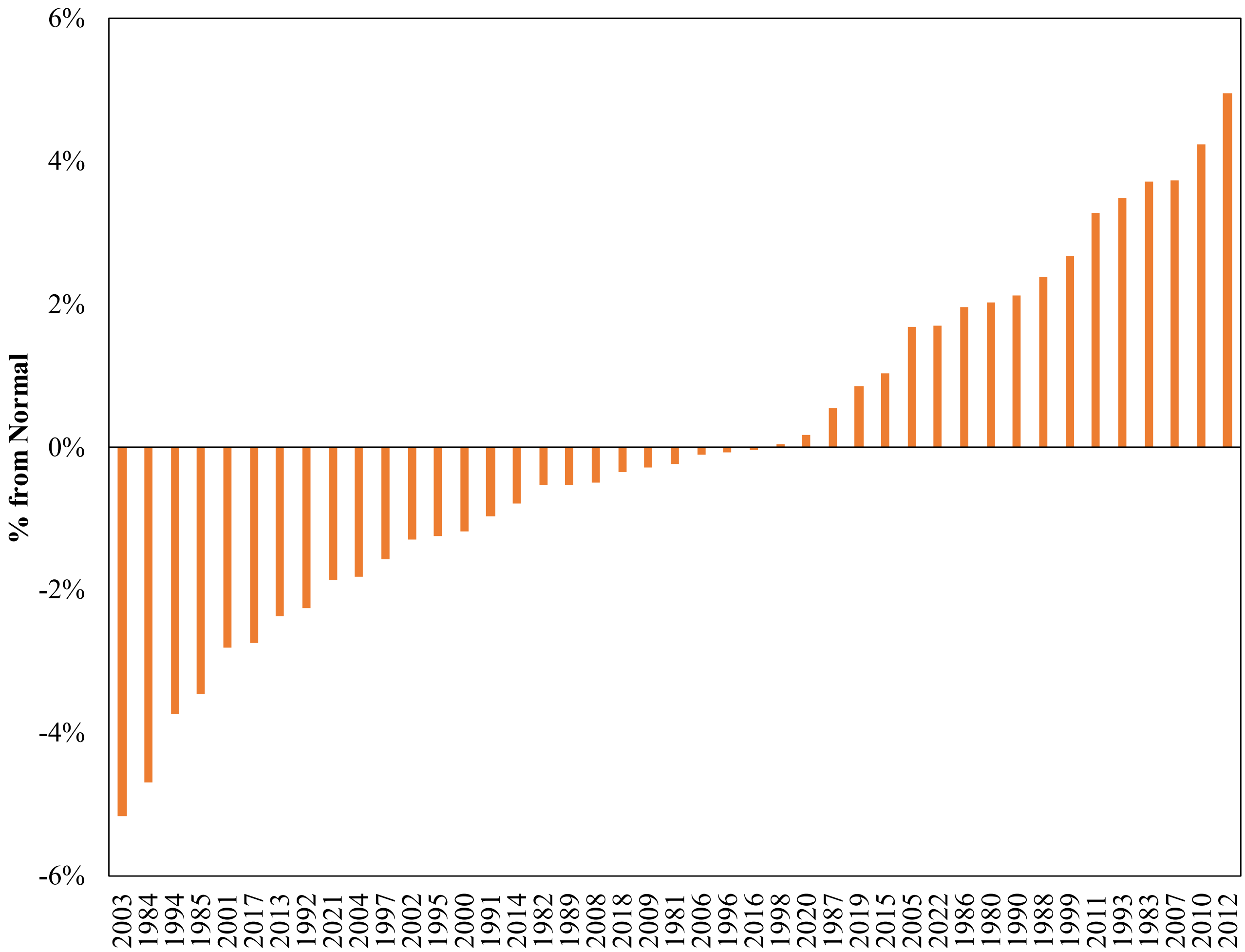


Figure 5. DEP-E Winter Peak Weather Variability

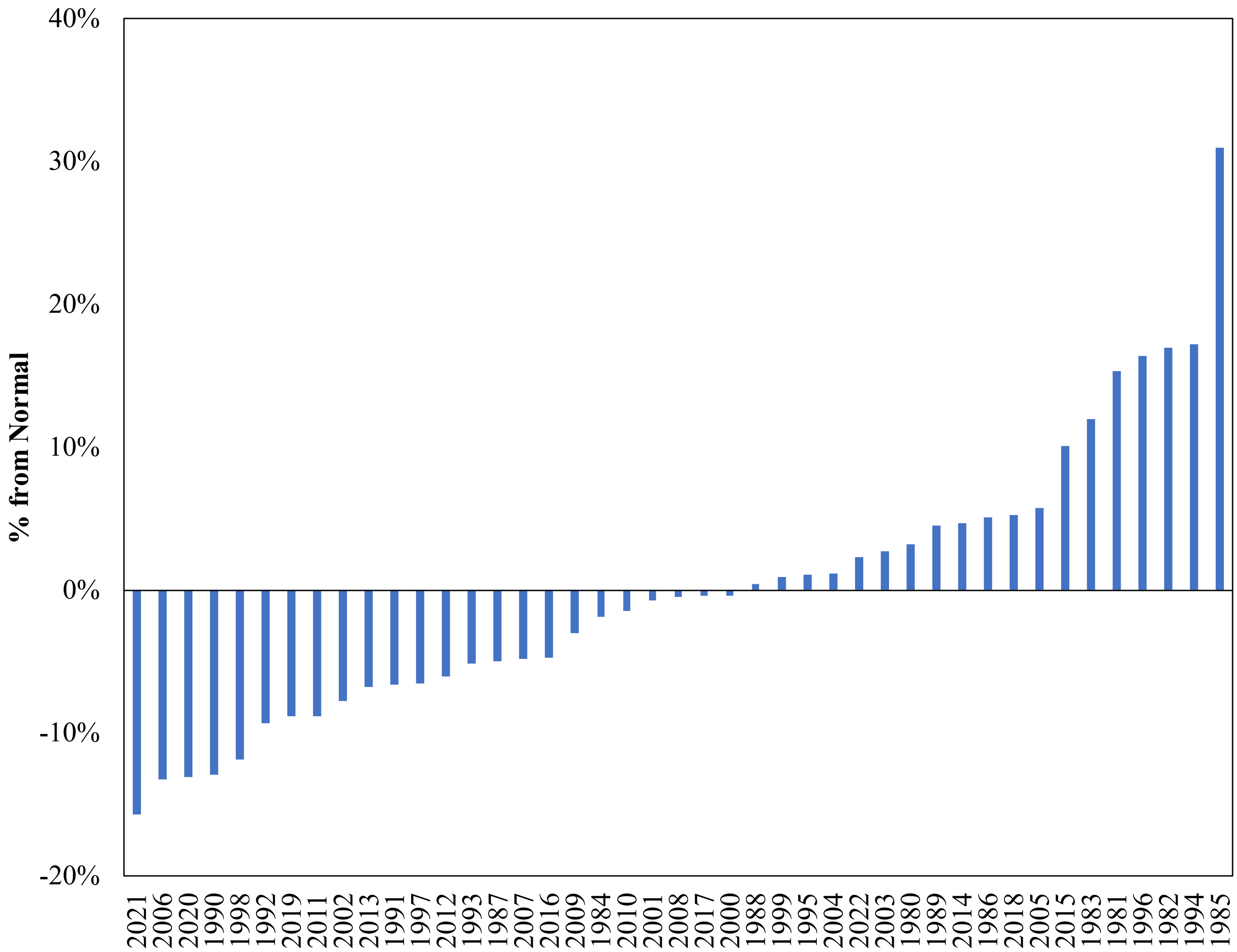


Figure 6. DEP-W Summer Peak Weather Variability

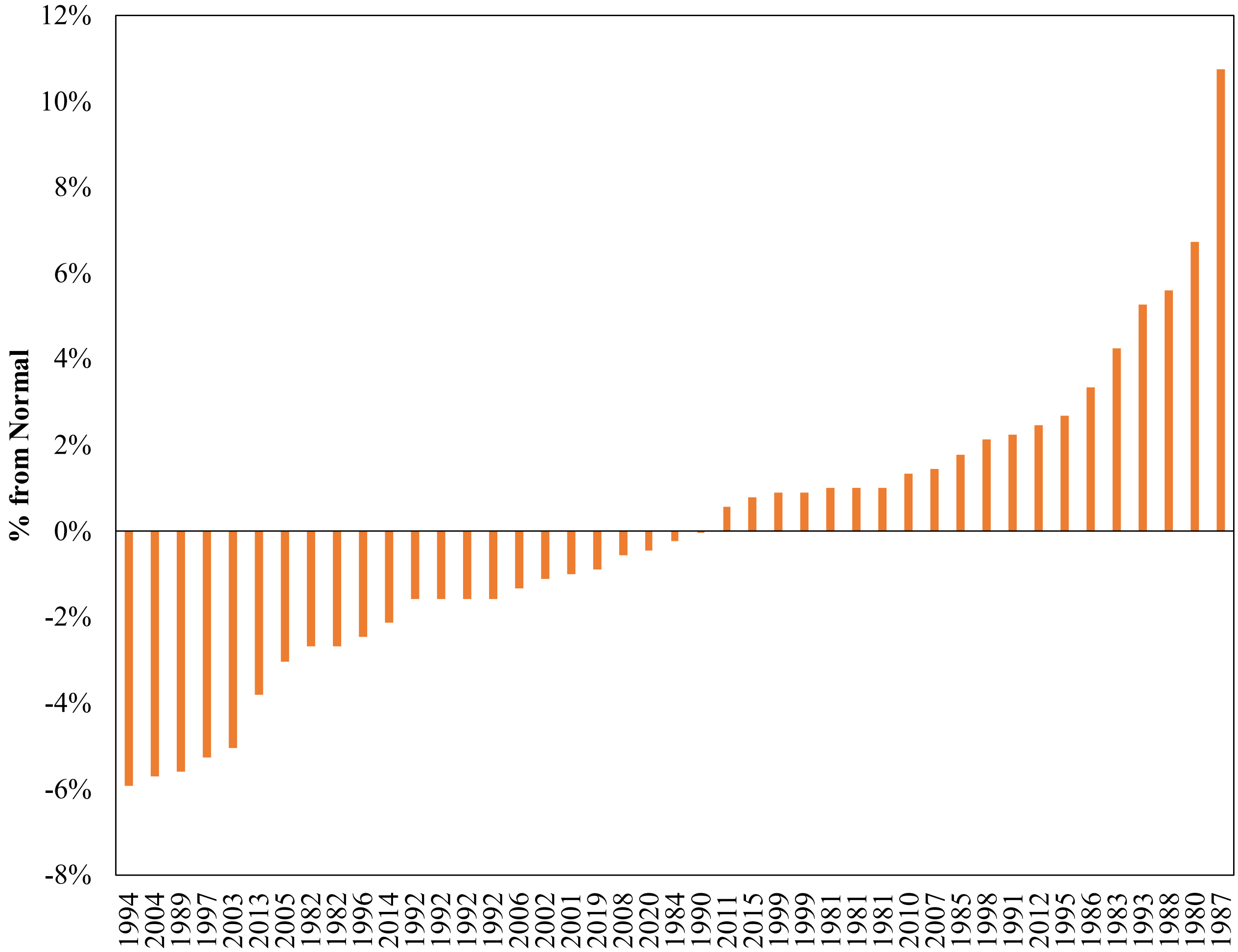
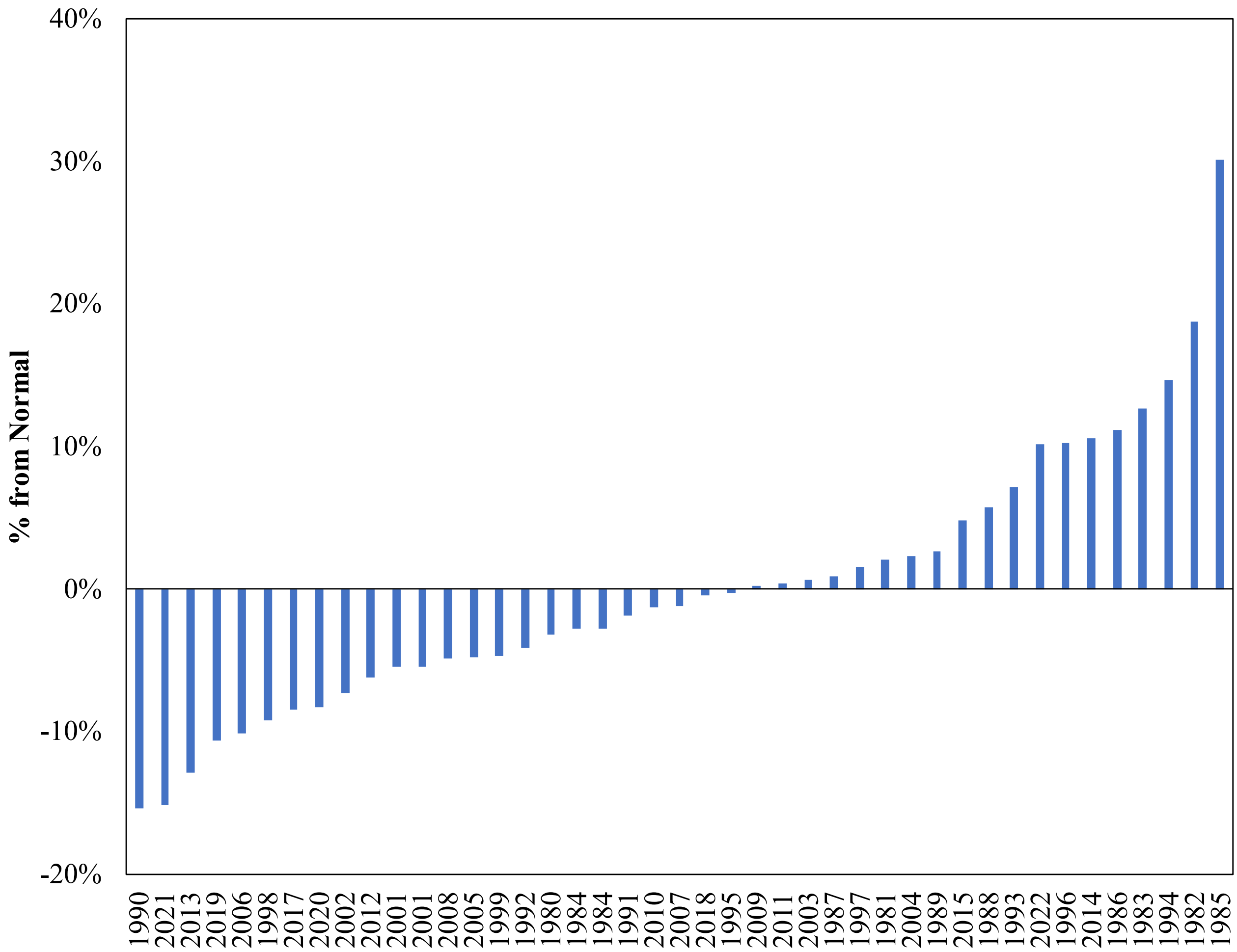


Figure 7. DEP-W Winter Peak Weather Variability



Economic Load Forecast Error

The same economic load forecast error multipliers used in the 2023 Resource Adequacy were used for this Study. Because these assumptions are included in the base case and the change case, they have minimal impact on the results of the Study. The economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their four-year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. The economic load forecast error distribution was developed using Moody's Analytics data. To estimate the economic load forecast error, the forecasts of both state population and

Gross Domestic Product ("GDP") for different economic scenarios were used to determine the percent change from each economic scenario to the baseline scenario. The Moody's estimated likelihood of these percent changes was then applied, and the percent changes were adjusted by a factor of 0.4 which acknowledges that the load does not grow at a one-to-one ratio with GDP. The final distribution used in the study is provided in Table 2. As an illustration, 27% of the time it is expected that load will be over-forecasted by 2.31% four years out. Within the simulations, when DEC or DEP over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the forty-three weather years and applied each of these 3 load forecast error points to create 129 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability (%)
0.9806	27.0%
1.00	46.0%
1.0231	27.0%

B. Solar Shape Modeling

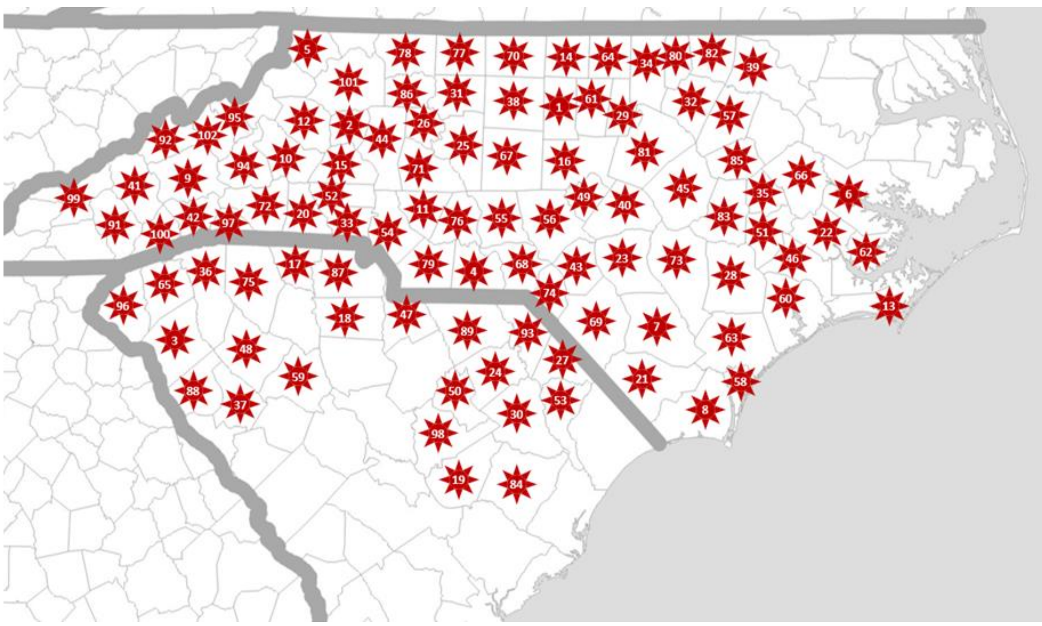
Table 3 shows the solar capacity levels that were analyzed. The solar penetration scenarios included two solar tranches which represent the expected amount of solar capacity that will be seen over the next 3-5 years, which is consistent with the 2027 study year.

Table 3. Solar Capacity Penetration Levels

	DEC MW	DEP MW	Total MW
Tranche 1	1,873	3,590	5,463
Tranche 2	2,738	4,392	7,130

Similar to load shapes, the solar units were simulated with forty-three solar shapes representing forty-three years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. Figure 8 shows the county locations that were used, which represents a wide geographical area across both DEC and DEP balancing areas.

Figure 8. Solar Profile Locations



The differing solar tranches were developed based on the Base Case for the 2023 Resource Adequacy Study, shown in Table 4. In order to decrease up or down capacity from these total levels, the bifacial single axis tracking levels were proportionately adjusted. For DEC Tranche 1, all of the bifacial and a portion of single-axis tracking had to be removed since only 1,873 MW of solar was being modeled for that scenario.

Table 4. Solar Capacity by Tranche

Unit Type	Inverter Loading Ratio (ILR)	DEC Capacity (MW)	DEP Capacity (MW)
Solar Fixed	1.3	1,142	3,161
Solar Fixed	1.6	121	239
Solar Single-Axis Tracking	1.3	575	179
Solar Single-Axis Tracking	1.6	258	164
Solar Bifacial Single-Axis Tracking	1.4	809	765
Total		2,905	4,507

Figures 9-11 shows Average January profiles for fixed, single-axis tracking, and bifacial solar resources. While the hourly shapes are important, it is the intra hour volatility that is discussed in the next section that drives the SISC.

Figure 9. Average January Output for Fixed Tilt

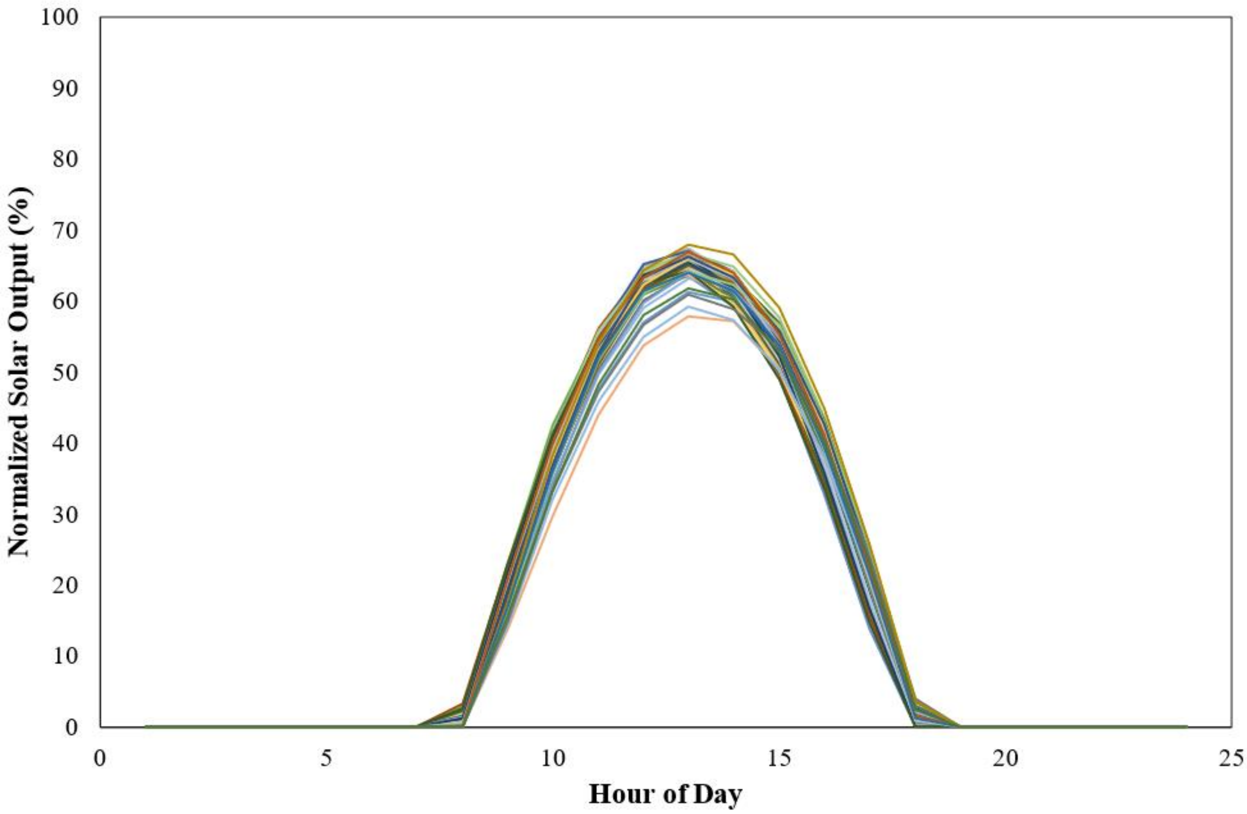


Figure 10. Average January Output for Monofacial Single-Axis Tracking

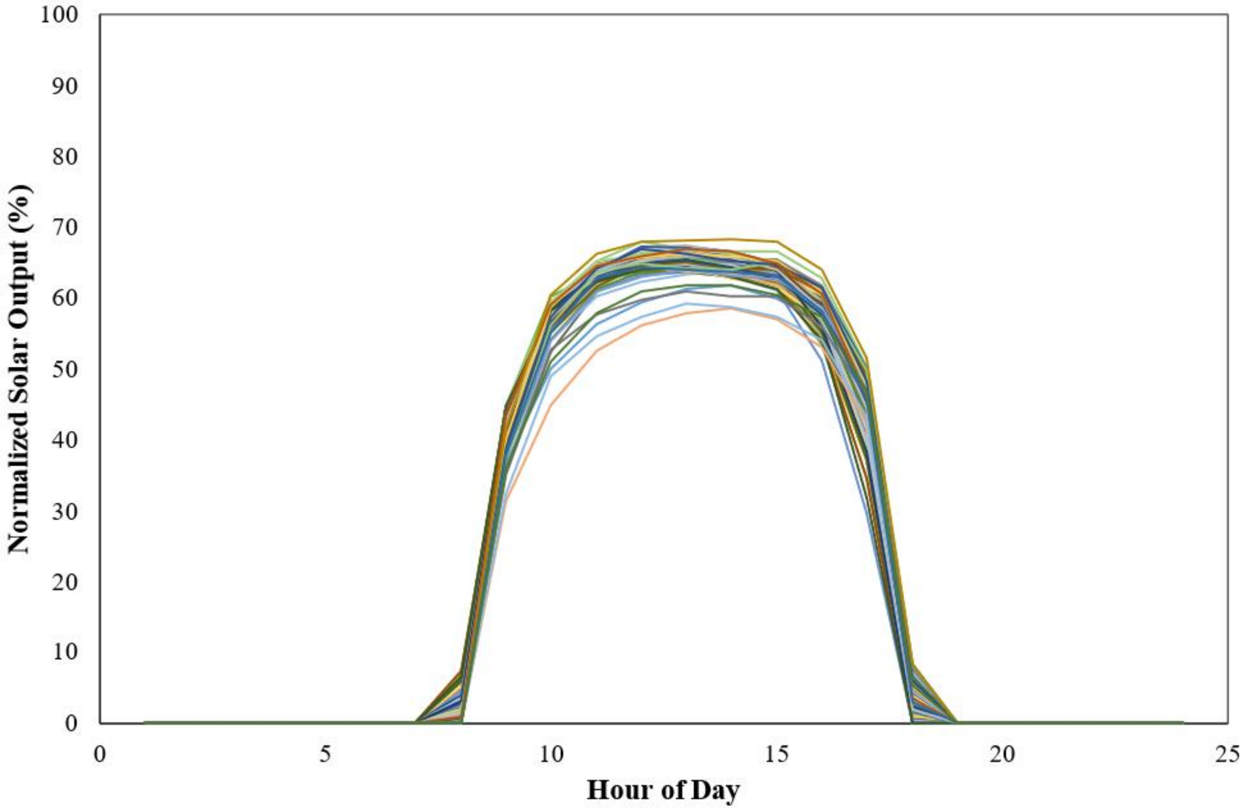
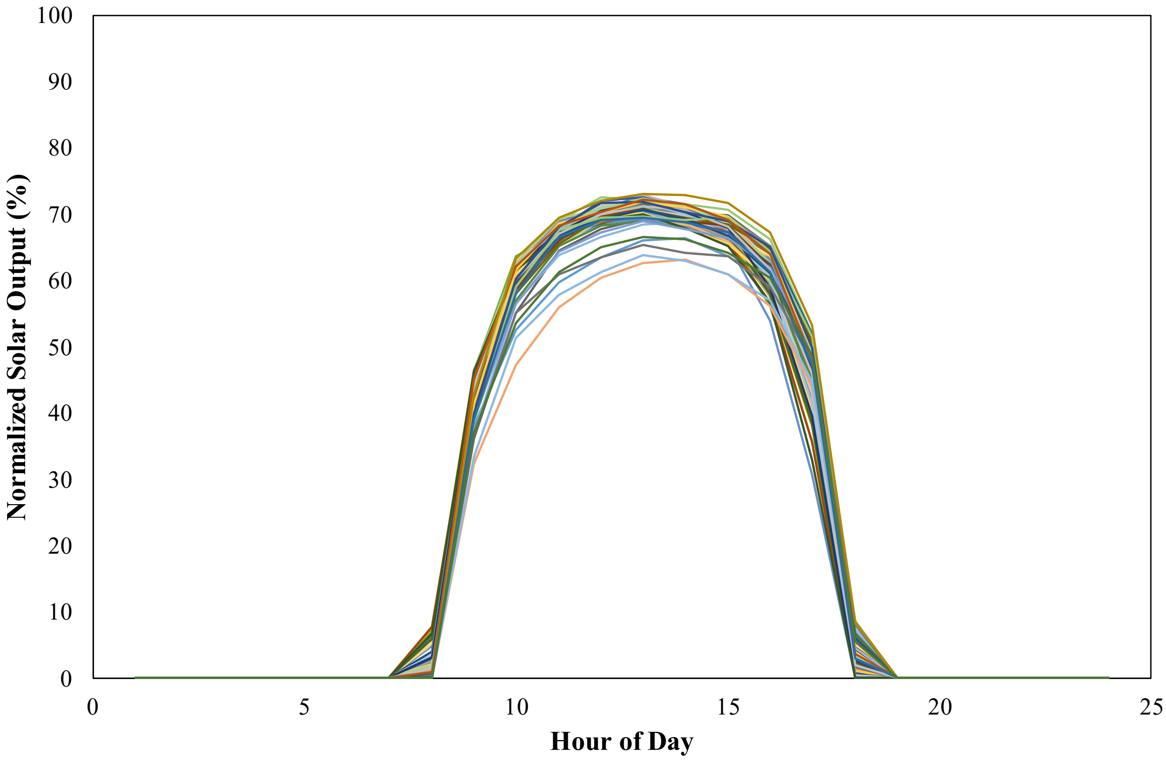


Figure 11. Average January Output for Bifacial Single-Axis Tracking



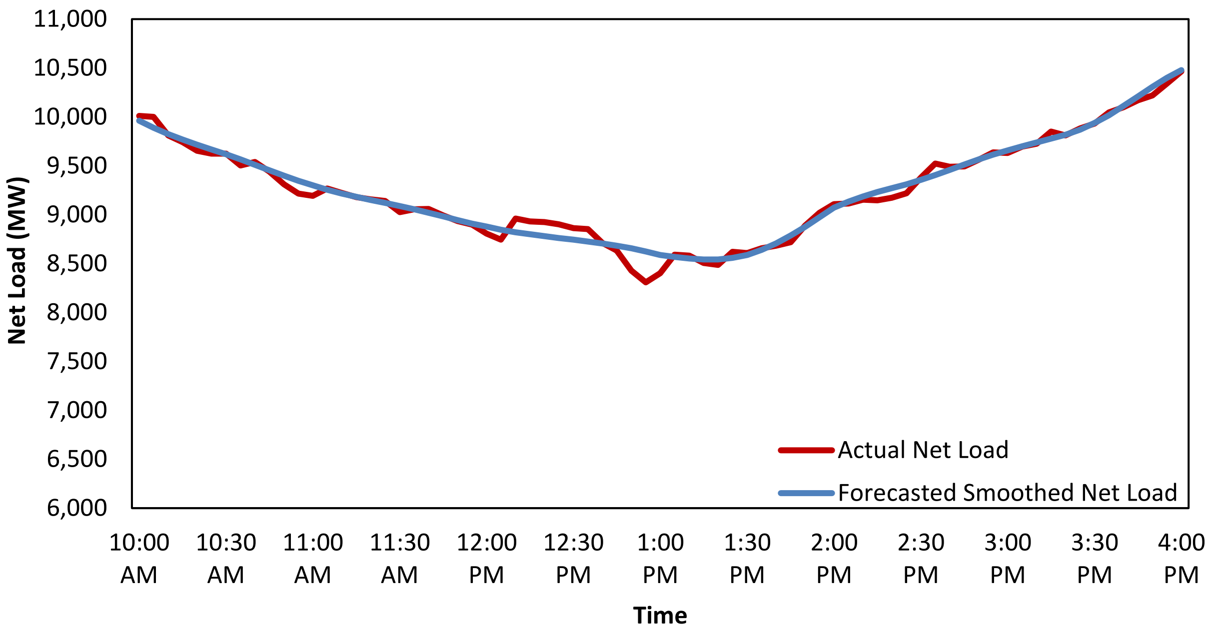
C. Load and Solar Volatility

For purposes of understanding the economic and reliability impacts of net load uncertainty, SERVM captures the implications of unpredictable intra-hour volatility. To develop data to be used in the SERVM simulations, Astrapé used historical five-minute data for load and solar. Within the simulations, SERVM commits to the expected net load and then has to react to intra hour volatility as seen in history which may include ramping units suddenly or starting quick start units.

Intra-Hour Forecast Error and Volatility

Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 12. The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute-to-minute basis. The solution to resolve the system's inability to meet load on a minute-to-minute basis is to increase operating reserves or add more flexibility to the system, which both result in additional costs.

Figure 12. Volatile Net Load vs. Smoothed Net Load



The load volatility is shown in Table 5 below and is based on one year of 5-minute load data from 2022 in DEC and DEP. The 5-minute variability in load is quite low, ranging mostly between +/-1% on a normalized basis. The load volatility is included in the base case and the change cases. With no intermittent resources on the system, this is the net load volatility assumed in the modeling.

Table 5. Load Volatility

Normalized Divergence (%)	Probability (%)
-2	0.000%
-1.75	0.000%
-1.5	0.003%
-1.25	0.010%
-1	0.138%
-0.75	1.145%
-0.5	8.906%
-0.25	43.174%
0	34.472%
0.25	10.106%
0.5	1.737%
0.75	0.262%
1	0.037%
1.25	0.005%
1.5	0.006%
1.75	0.001%
2	0.000%

The intra hour volatility of solar is higher than intra hour load volatility and is based on historical data from January of 2018 to December of 2022. The 5-minute data was analyzed, and days with anomalies or missing recordings were removed from the dataset. The historical data was aggregated at the DEC level and the DEP level. The historical DEC data represents solar tranches of 528 MW and 947 MW; the historical DEP data represents solar tranches of 1,925 MW, 2,624 MW, and 2,886 MW; and then the Combined historical data represents 3,652 MW. Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, the fact that larger units are coming on may dampen the diversity benefit. In line with the 2021 Study and feedback from the TRC, the raw historical data volatility was utilized and then extrapolated based on the diversity benefit trend seen in the historical data. The historical levels outlined above were used to extrapolate the additional levels utilized. The volatility declines with additional solar, and this dataset was trended out to 7,000 MW of solar as shown in Figure 13. The figure measures the 99th percentile of the 5-minute solar deviation as a percentage of nameplate capacity. This measure declines as solar penetration increases.

Figure 13. Declining Volatility as a Function of Solar Capacity

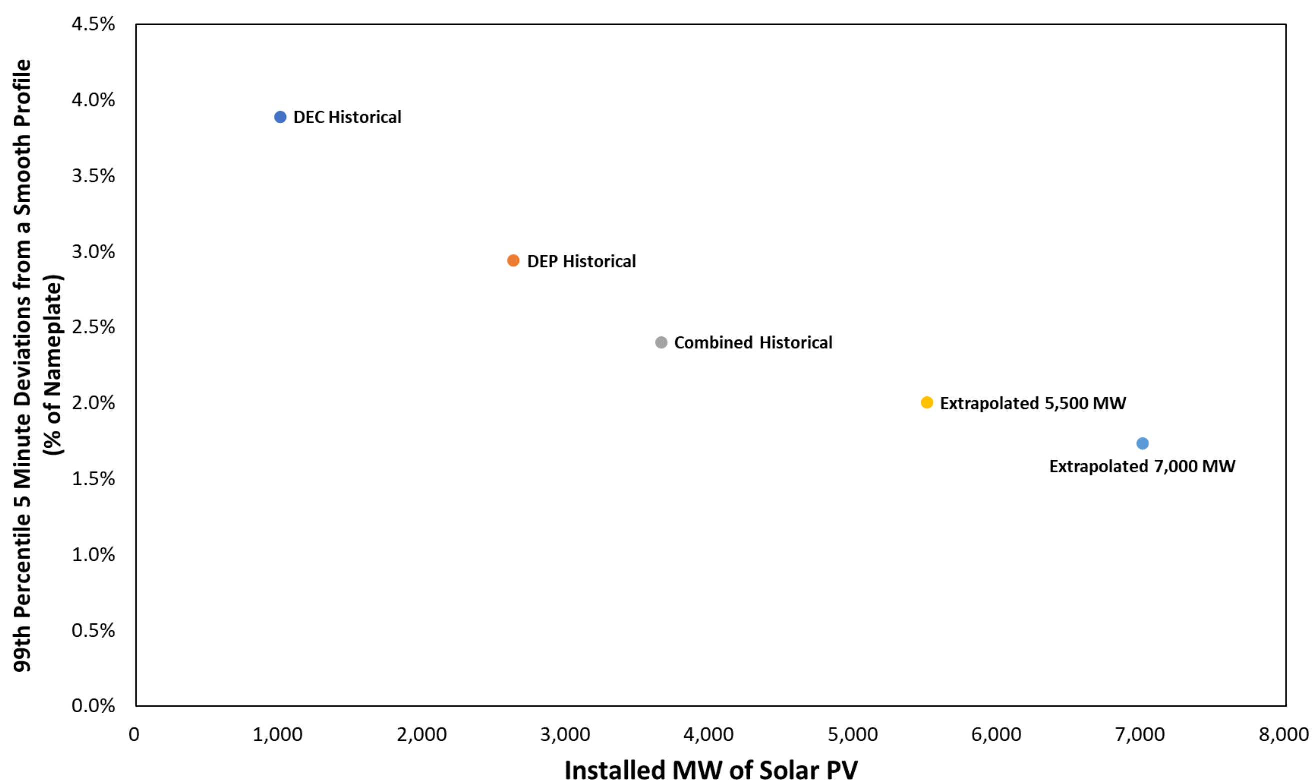


Table 6 shows the probability at different 5-minute divergence levels across the 5 solar penetrations in the previous Figure. The table shows a steady decline in unitized volatility due to diversity benefits of larger portfolios.

Table 6. Solar Volatility

5 Minute Normalized Divergence	Probability %				
Solar Capacity Level MW	1,000	2,624	3,652	5,500	7,000
-14%	0.0%	0.00%	0.00%	0.00%	0.00%
-13%	0.0%	0.00%	0.00%	0.00%	0.00%
-12%	0.0%	0.00%	0.00%	0.00%	0.00%
-11%	0.0%	0.00%	0.00%	0.00%	0.00%
-10%	0.0%	0.00%	0.00%	0.00%	0.00%
-9%	0.0%	0.00%	0.00%	0.00%	0.00%
-8%	0.1%	0.01%	0.00%	0.00%	0.00%
-7%	0.1%	0.02%	0.00%	0.00%	0.00%
-6%	0.2%	0.07%	0.01%	0.00%	0.00%
-5%	0.5%	0.23%	0.07%	0.02%	0.01%
-4%	1.1%	0.64%	0.36%	0.15%	0.06%
-3%	2.3%	1.68%	1.49%	0.92%	0.56%
-2%	5.0%	4.86%	5.23%	4.47%	3.73%
-1%	17.6%	17.58%	19.84%	21.44%	22.64%
0%	63.6%	67.36%	65.78%	67.44%	68.66%
1%	5.2%	4.94%	5.44%	4.55%	3.76%
2%	2.2%	1.66%	1.38%	0.84%	0.51%
3%	1.0%	0.58%	0.31%	0.15%	0.06%
4%	0.5%	0.24%	0.07%	0.02%	0.01%
5%	0.2%	0.07%	0.02%	0.00%	0.00%
6%	0.1%	0.04%	0.00%	0.00%	0.00%
7%	0.1%	0.01%	0.00%	0.00%	0.00%
8%	0.0%	0.00%	0.00%	0.00%	0.00%
9%	0.0%	0.00%	0.00%	0.00%	0.00%
10%	0.0%	0.00%	0.00%	0.00%	0.00%
11%	0.0%	0.00%	0.00%	0.00%	0.00%
12%	0.0%	0.00%	0.00%	0.00%	0.00%
13%	0.0%	0.00%	0.00%	0.00%	0.00%
14%	0.0%	0.00%	0.00%	0.00%	0.00%

D. Conventional Thermal Resources

Conventional thermal resources owned by the Companies and purchased as Purchase Power Agreements were modeled consistent with the Companies' portfolio for the 2027 study year. These resources are economically committed and dispatched to load on a 5-minute basis. Similar to the resource adequacy study, the capacities of the units are defined as a function of temperature in the simulations allowing for higher capacities in the winter compared to the summer. SERVM dispatches resources on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve spinning and load following reserves as long as the minimum capacity level is less than the maximum capacity. Units with automatic generation control (AGC) capability are allowed to serve regulation. Fuel prices were updated based on the Companies' 2023 Carbon Plan and Integrated Resource Plan filing in North Carolina[4] and Integrated Resource Plan filing in South Carolina.[5]

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data and is consistent with the 2023 Resource Adequacy Study. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar units. The events are entered using the following variables:

<u>Full Outage Modeling</u>
Time-to-Repair Hours

[4] Verified Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas LLC and Duke Energy Progress LLC, Docket No. E-100, Sub 190 (filed Aug. 17, 2023).

[5] Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's 2023 Integrated Resource Plan, Docket Nos. 2023-8-E & 2023-10-E (filed Aug. 15, 2023).

Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
Estimates based on future scheduled maintenance were utilized in the modeling.

To illustrate the outage logic, assume that from 2018 – 2022, a generator had 12 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically committed for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

E. Hydro, Pump Storage Modeling, and Battery Modeling

The hydro portfolios in DEC and DEP are modeled as scheduled hydro and are used for shaving the daily net peak load but also includes minimum flow requirements. By modeling the hydro resources in this fashion, the model captures the appropriate amount of capacity dispatched during peak periods and is consistent with the 2023 Resource Adequacy Study.

In addition to conventional hydro, DEC owns and operates a pump hydro fleet consisting of 2,420 MW[6]. The fleet consists of two pump storage plants: (1) Bad Creek at a 1,640 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions. While the pumped-storage units have fast ramping capability, the range from minimum to maximum for generating is fairly low, providing minimal intra hour load following benefit for solar integration. The resources offer single speed pumping which doesn't allow for ramping capability during pumping. The pump storage fleet does assist in hourly energy balances which reduces curtailment significantly for DEC. Table 7 provides the characteristics of the pump-storage fleet.

[6] The Bad Creek station is modeled with a maximum capacity of 1,640 MW (410 MW per unit). Each of the four units can individually run at a maximum rated capacity of 420 MW. However, due to power tunnel limitations, all four units cannot run at their maximum rated capacity simultaneously. Therefore, if all four units were called to operate at maximum possible generation, they would be de-rated by 10 MW each with the highest possible station output at 1,640 MW.

Table 7. Pump Storage Resources

DEC Pump Storage Unit	**Gen Capacity** (MW)	**Gen Capacity Min** (MW)	**Pumping Capacity** (MW)	**Pumping Min Capacity** (MW)	**Pond Capacity** (MWh)	**Ramp Rate** (MW/min)
Bad Creek_1	420	320	375	375	8,798	40
Bad Creek_2	420	320	375	375	8,798	40
Bad Creek_3	420	320	375	375	8,798	40
Bad Creek_4	420	320	375	375	8,798	40
Jocassee_1	195	185	205	205	3,803	40
Jocassee_2	195	185	205	205	3,803	40
Jocassee_3	195	185	205	205	3,803	40
Jocassee_4	195	185	205	205	3,803	40

The SISC Study also modeled 370 MW of standalone battery capacity in DEC and 333 MW in DEP. The batteries are allowed to be used for economic arbitrage and serve ancillary services to avoid flexibility excursions based on their state of charge and output capability. There were no constraints modeled on battery flexibility or number of cycles.

F. Southeastern Energy Exchange Market (SEEM)

In order to capture the benefits of SEEM, Astrapé analyzed historical transactions from November 2022 through September of 2023. Based on the historical data, the SISC Study included additional capacity of 100 MW in DEC and 100 MW in DEP that the Companies could dispatch within 15 minutes. The 100 MWs was split into four 25 MW units in both DEC and DEP meaning the system had access to 25 MW or up to 100 MW of energy blocks. Based on historical transaction pricing, Table 8 shows the costs assigned to these blocks of capacity ranged from $31/MWh to $58/MWh.

Table 8. SEEM Resources

MW Size	DEP Price ($/MWh)	DEC Price ($/MWh)
25	38	31
25	45	44
25	50	51
25	56	58

G. Demand Response Modeling

Demand Response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints consistent with the 2023 Resource Adequacy Study. For 2027, DEC assumed 1,386 MW of Demand Response in the summer and 822 MW in the winter. DEP assumed 906 MW of summer Demand Response capacity and 434 MW of Demand Response winter capacity.

H. Study Topology

As discussed previously, the Companies were modeled as islands for this analysis because each balancing area is responsible for its own NERC requirements. By modeling in this manner, the required operating reserves and flexibility requirements are calculated for each of the Companies. Similar to the 2021 Study as recommended by the TRC, the analysis was performed assuming the Joint Dispatch Agreement (JDA) between DEC and DEP was utilized. In this scenario, each BA still holds its own operating reserves, but economic exchanges are allowed to reduce the costs of the additional load following requirements. The results sections show the results as an island and a combined DEC and DEP case.

I. Ancillary Services

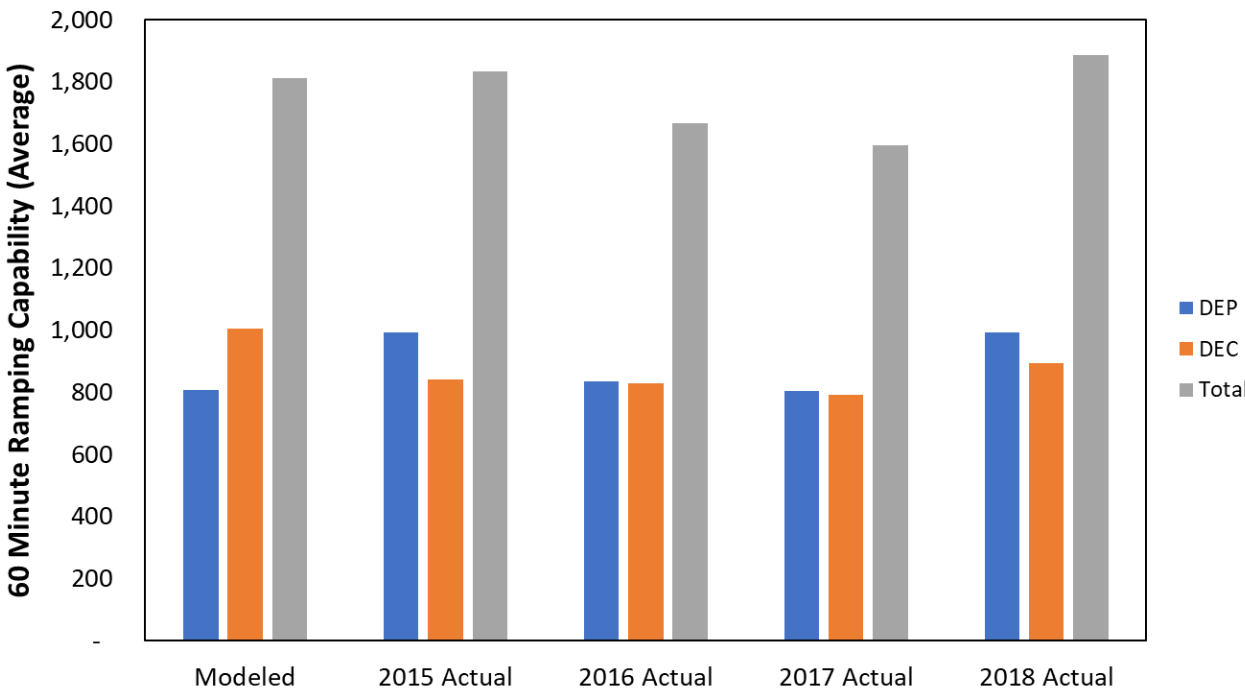
Ancillary service targets are input into SERVM. SERVM commits resources to meet energy needs plus ancillary service requirements. These ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, spinning reserves, load following reserves, and quick start reserves. Table 9 shows the definition of ancillary service for each study. Spinning reserves and load following up reserves are identical and represent the sum of the 10-minute ramping capability of each unit on the system. To maintain operational flexibility as solar resources are added, the load following up reserves are increased until the flexibility excursions seen in the "no solar" case are met. The load following up reserves represent an increase in ramping capability of the fleet meaning that more resources are turned on so that they can be operated further away from their maximum capacity level allowing for more ramping capability.

Table 9. Ancillary Services

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	10 Min Product served by units who have minimum load less than maximum load
Load Following Down Reserves	10 Min Product served by units who have minimum load less than maximum load
Load Following Up Reserves	10 Min Product served by units who have minimum load less than maximum load
Quick Start Reserves Requirement	Served by units who are offline and have quick start capability

To ensure the operating reserves were at reasonable levels for the "no solar" case, Astrapé compared the realized 60-minute ramping capability in the model to historical dispatch data during the 2015-2018 time period when there were lower solar levels on the system. This comparison is shown in Figure 14. While this comparison would never be expected to be exact due to differences in weather, loads, resource mix, fuel prices, and generator performance among other things it does show that the modeled levels are not unreasonable as a starting point to determine flexibility excursions in the no solar scenario. In the modeled scenario, battery capacity which did not exist in the historical data likely increases operating reserves in off peak periods as a battery provides operating reserves even if it is not charging or discharging. Non spinning reserves are available in all cases and SERVM uses those to mitigate flexibility excursions.

Figure 14. No Solar 60 Minute Ramping Capability Comparison



J. Flexibility Excursion

A flexibility excursion is calculated by the model as any day where resources could not meet load but there was additional installed capacity on the system. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. This is distinguished from a firm load shed event which is due to insufficient resources when operators are required to begin rolling blackouts.

III. Simulation Methodology

Since these flexibility excursions are low probability events, a large number of scenarios must be considered to accurately project these events. For this Study, SERVM utilized 43 years of historical weather and load shapes, 3 points of economic load growth forecast error, and 10 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 43 weather years * 5 load forecast errors * 10 unit outage iterations = 2,150 total iterations for each level of solar penetration simulated. Weather years and solar profiles were each given equal probability while the load forecast error multipliers were given their associated probabilities as reported in the input section of the report. This set of cases was simulated for each of the solar penetration levels in Table 10.

Table 10. Solar Penetration Levels

Tranche	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW	Total Cumulative MW
No Solar	0	0	0	0	0
Tranche 1	1,873	1,873	3,590	3,590	5,463
Tranche 2	865	2,738	802	4,392	7,130

For each case, and ultimately each iteration, SERVM commits and dispatches resources to meet load and ancillary service requirements on a 5-minute basis. As discussed in the load and renewable uncertainty sections, SERVM does not have perfect knowledge of the load or renewable resource output as it determines its commitment. SERVM begins with a week-ahead commitment, and as the prompt hour approaches the model is allowed to make adjustments to its commitment as units fail and more certainty around net load is gained. Ultimately, SERVM forces the system to react to these uncertainties while maintaining all unit constraints such as ramp rates, startup times, and min-up and min-down times. During each iteration, flexibility excursions and total costs are calculated where:

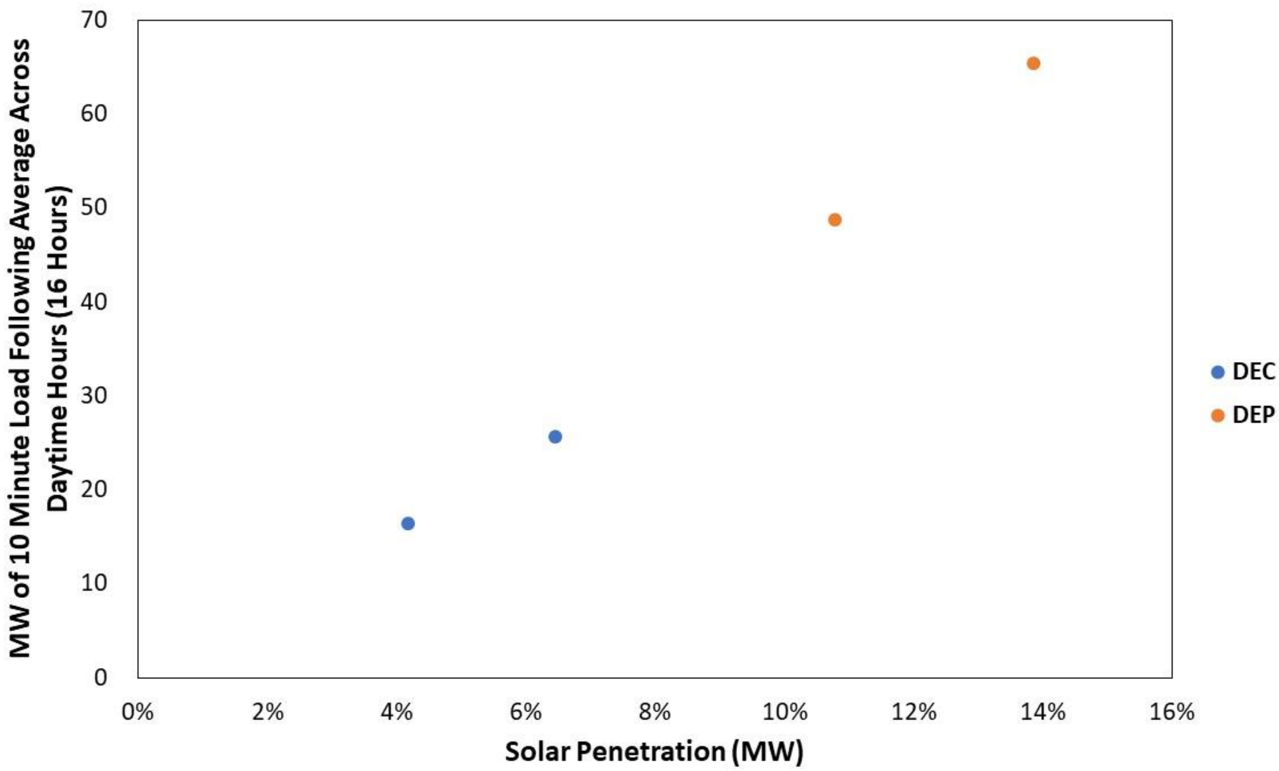
Total Costs = Fuel Costs + O&M Costs + Startup Costs

These flexibility excursions and cost components are calculated for each of the 2,150 iterations and weighted based on probability to calculate an expected total cost for each study simulated. As the systems are simulated from 0 MW of solar to several thousand MWs of solar, the net load volatility increases causing flexibility excursions to increase. In order to reduce these events down to the level that was seen in the no solar case, additional ancillary services (load following up reserves) are simulated in the model so the system can handle the larger net load volatilities. Renewable curtailment is also captured in the model, and it is noted that curtailment is used as load following in the model. The model also uses quick start resources in all scenarios modeled.

IV. Load Following Requirements

The Study added load following across the day to manage the solar ramps and volatility and targeted additions based on when the flexibility excursions were occurring. Figure 15 shows the quantified required increase in operating reserves for Tranche 1 and 2 for both DEC and DEP as a percentage of solar penetration. The additions are correlated to solar penetration as additional solar increases the load following reserves requirement.

Figure 15. Quantified Required Increase in Operating Reserves as a Function of Solar Penetration



Figures 16-18 show heat maps of the flexibility excursions on a 12x24 basis for the DEC no solar case, DEC Tranche 1, and DEC Tranche 2 cases. In the no solar case, any flexibility excursions are during high load periods when operating reserves have a tendency to be lower.

Figure 16. DEC No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
2	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	7.1%	0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
8	5.4%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.2%	0.2%
9	6.5%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.2%
10	5.9%	0.8%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.2%
11	2.1%	0.8%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.7%
12	3.9%	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
13	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	1.8%	4.6%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.1%	0.0%	0.7%	1.3%	2.3%	0.5%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.3%	0.1%	1.1%	1.6%	0.7%	0.1%	0.1%	0.1%	0.0%
18	0.1%	0.1%	0.0%	0.0%	0.3%	0.3%	3.6%	2.5%	1.0%	0.1%	0.0%	0.0%
19	0.1%	0.2%	0.4%	0.1%	0.2%	2.9%	0.6%	1.4%	0.1%	0.1%	0.2%	0.1%
20	0.4%	0.4%	0.3%	0.1%	0.1%	0.9%	3.0%	1.6%	0.2%	0.6%	0.6%	0.3%
21	0.2%	0.6%	0.1%	0.4%	1.5%	0.5%	0.7%	1.0%	0.6%	0.7%	0.2%	0.4%
22	0.3%	0.2%	0.3%	0.4%	0.5%	0.4%	0.6%	0.6%	0.3%	0.4%	0.3%	0.2%
23	0.1%	0.1%	0.2%	0.2%	0.3%	0.4%	0.5%	0.3%	0.2%	0.0%	0.2%	0.1%
24	0.0%	0.0%	0.1%	0.1%	0.4%	0.3%	0.4%	0.4%	0.7%	1.6%	0.1%	0.0%

As solar is added, the flexibility excursions move towards later in the afternoon or during solar ramp up periods as shown in Figures 17 and 18.

Figure 17. DEC Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
2	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
5	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.4%	1.7%	0.2%	0.7%	0.1%	0.0%	0.0%	0.0%	0.1%	0.2%	0.2%	0.1%
7	0.6%	1.1%	1.2%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.7%	0.5%	2.1%
8	5.8%	0.2%	0.6%	1.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.5%	0.4%	0.3%
9	4.8%	0.9%	1.2%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%	1.0%	2.5%
10	4.0%	1.6%	1.2%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.7%	1.7%
11	1.8%	1.1%	0.6%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.4%	0.8%
12	0.4%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	1.4%	0.0%	0.6%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.3%	0.3%	0.2%	2.2%	0.0%	0.1%
17	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.3%	0.6%	0.3%	4.7%	0.2%	0.2%
18	0.3%	0.5%	0.3%	1.1%	0.7%	0.3%	0.2%	0.3%	0.5%	4.2%	0.4%	0.0%
19	0.3%	0.3%	1.1%	2.7%	0.8%	0.4%	0.2%	0.3%	0.2%	2.1%	0.3%	0.3%
20	0.6%	0.6%	0.3%	0.1%	0.2%	0.1%	0.6%	0.1%	0.3%	2.1%	0.2%	0.3%
21	0.3%	0.4%	0.3%	0.2%	0.2%	0.1%	0.7%	0.2%	0.3%	2.4%	0.2%	0.4%
22	0.2%	0.2%	0.2%	0.3%	0.3%	1.3%	0.8%	0.5%	0.4%	0.5%	0.3%	0.3%
23	0.3%	0.1%	0.2%	0.4%	0.4%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%	0.1%
24	0.3%	0.0%	0.0%	0.1%	0.1%	0.4%	0.3%	0.3%	0.2%	0.0%	0.0%	0.1%

Figure 18. DEC Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
2	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.6%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.5%	0.0%	0.4%	0.4%	1.4%	0.0%	0.0%	0.1%	0.7%	0.8%	0.0%	0.1%
7	4.1%	0.5%	0.9%	1.0%	0.3%	0.0%	0.0%	0.0%	0.1%	0.5%	0.5%	0.9%
8	1.6%	0.7%	1.2%	0.6%	0.3%	0.0%	0.0%	0.0%	0.1%	0.9%	0.7%	0.3%
9	2.3%	1.6%	1.4%	0.7%	0.3%	0.0%	0.0%	0.0%	0.0%	1.1%	1.8%	1.7%
10	2.1%	1.4%	1.2%	0.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.3%	1.0%	2.8%
11	0.5%	0.8%	0.5%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.3%	0.5%
12	0.4%	0.2%	0.2%	0.1%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
13	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%
17	0.1%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.3%	0.2%	0.4%	0.1%	0.1%
18	0.2%	1.4%	0.3%	2.1%	1.6%	0.4%	0.6%	0.7%	2.4%	5.2%	2.1%	0.3%
19	0.3%	0.1%	2.0%	8.2%	2.9%	1.7%	1.1%	1.8%	1.8%	0.1%	0.1%	0.2%
20	0.3%	0.2%	0.2%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	0.1%	0.1%	0.3%
21	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.3%	0.1%	0.2%
22	0.5%	0.1%	0.1%	0.3%	0.6%	0.4%	1.7%	0.6%	0.3%	0.3%	0.2%	0.2%
23	0.3%	0.1%	0.2%	0.2%	0.5%	0.2%	0.2%	0.3%	0.2%	0.2%	0.2%	0.1%
24	0.4%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%

Figures 19-20 show the load following targets input into the model to lower the amount of flexibility excursions until they are at the same level as the no solar case. While these are the targets for the commitment, the realized incremental reserves are output as reported previously in Figure 15. Because the modeling can take advantage of periods where there are excess reserves due to commitment constraints on resources, the realized additional load following will always be less than the change in targets. In other words, there are periods where the target was increased but the system is already providing ample reserves on some of those days, so the incremental realized reserves reported in the results are less than these target input changes. These targets were adjusted upward in an iterative process by analyzing when the flexibility excursions were occurring and were increased until the number of events approached the number of events in the no solar case.

Figure 19. DEC Tranche 1: Final Incremental Load Following Targets (MW)

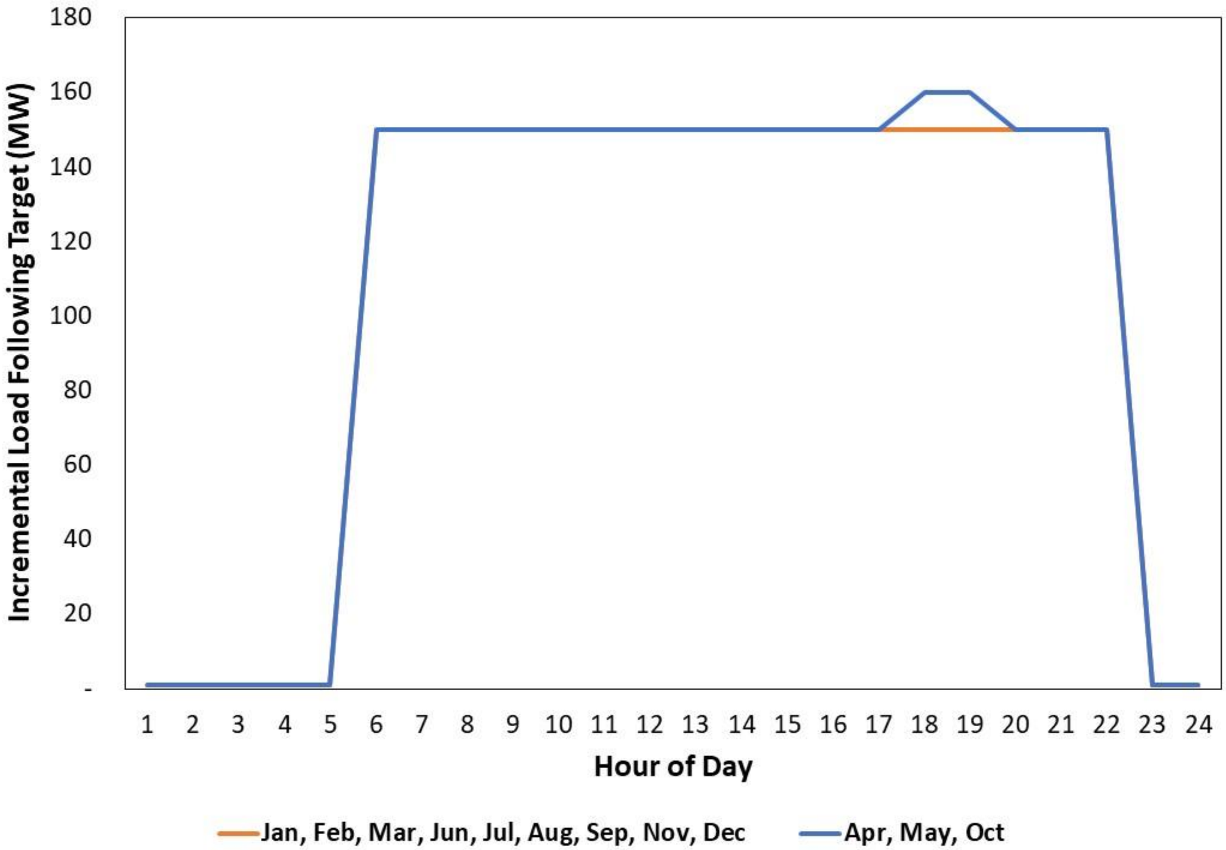
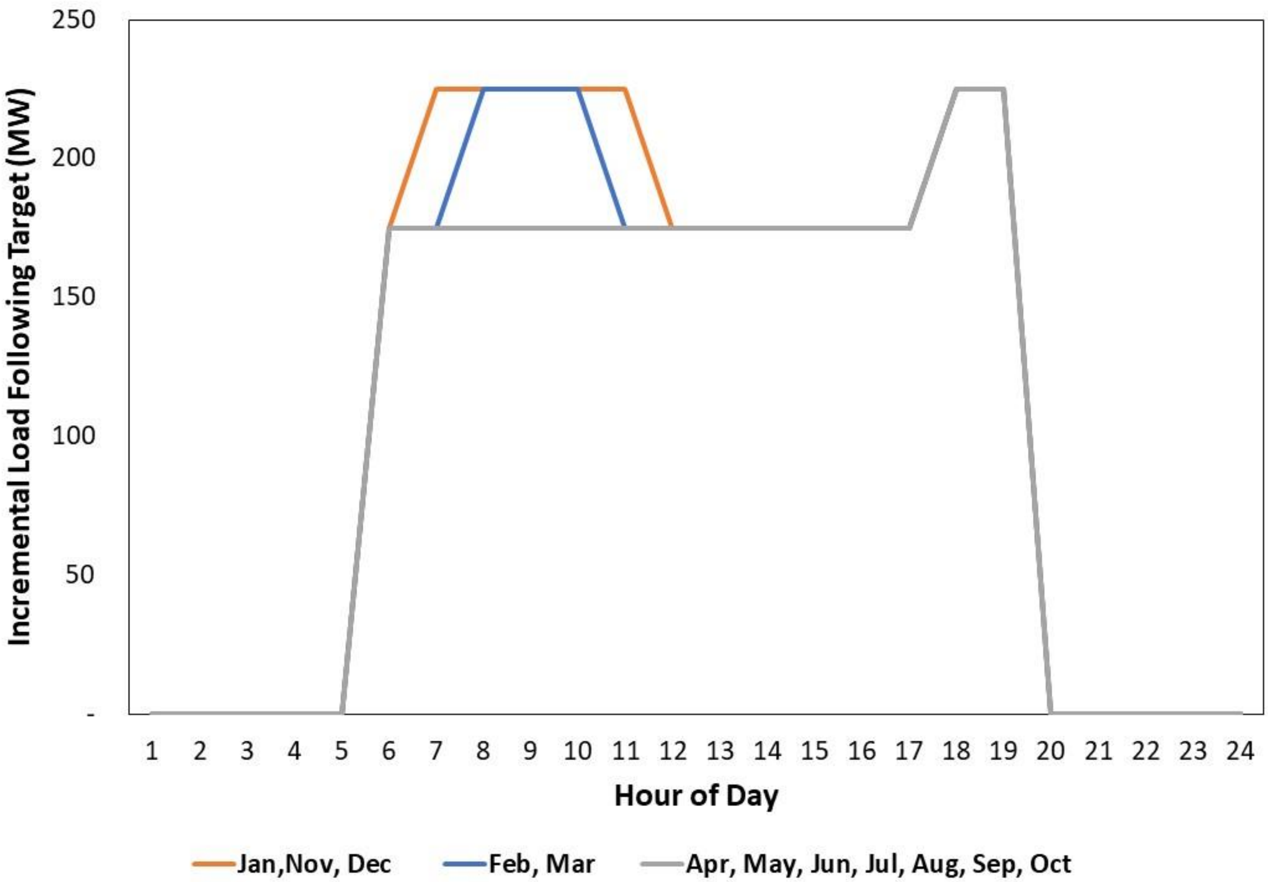


Figure 20. DEC Tranche 2: Final Incremental Load Following Targets (MW)



The same figures are shown for DEP in Figures 21-25 below.

Figure 21. DEP No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
5	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.6%
6	0.5%	0.2%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.3%
7	0.6%	1.0%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	2.8%
8	1.1%	0.5%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%
9	2.0%	0.1%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
10	0.9%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
11	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.1%	0.0%	0.0%	0.1%	0.0%	0.3%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%
14	0.2%	0.0%	0.0%	0.2%	0.0%	0.2%	3.0%	1.1%	0.1%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	1.1%	0.1%	0.3%	6.4%	1.4%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	1.7%	0.2%	1.1%	11.0%	0.9%	0.1%	0.1%	0.0%	0.0%
17	0.0%	0.0%	0.0%	1.3%	0.2%	2.0%	12.1%	2.6%	0.1%	0.0%	0.0%	0.1%
18	0.0%	0.0%	0.0%	0.7%	0.2%	1.4%	9.7%	2.1%	0.1%	0.0%	0.1%	0.1%
19	0.5%	0.4%	0.2%	0.1%	0.0%	0.9%	4.3%	0.1%	0.0%	0.1%	0.1%	1.6%
20	0.4%	0.4%	0.2%	0.0%	0.0%	0.6%	0.4%	0.0%	0.0%	0.0%	0.2%	1.7%
21	0.1%	0.2%	0.1%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
22	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.8%
23	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 22. DEP Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.3%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
6	2.1%	0.4%	0.3%	0.6%	1.5%	0.1%	0.1%	0.0%	0.1%	0.3%	0.1%	0.5%
7	2.8%	0.7%	0.5%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.8%	0.3%	1.4%
8	2.6%	0.0%	0.1%	0.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	1.6%
9	0.1%	0.2%	0.0%	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	0.1%	0.1%	0.4%
10	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
11	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%	0.2%	0.0%	0.0%	0.1%
17	0.0%	0.0%	0.0%	0.1%	0.2%	0.6%	0.5%	0.8%	0.9%	0.8%	0.6%	0.1%
18	0.0%	0.5%	0.4%	1.2%	2.9%	1.8%	2.0%	3.4%	11.7%	3.4%	0.0%	0.0%
19	0.1%	0.1%	0.1%	4.6%	12.6%	11.6%	10.1%	4.3%	0.2%	0.0%	0.1%	0.4%
20	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 23. DEP Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
4	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.2%	0.0%	0.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%
6	0.5%	1.3%	0.2%	1.4%	2.3%	0.1%	0.2%	0.0%	0.2%	0.3%	0.2%	1.1%
7	1.2%	2.8%	0.4%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.7%	0.4%	2.1%
8	1.7%	0.9%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%
9	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%
10	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.2%
11	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
17	0.1%	0.0%	0.0%	0.1%	0.2%	0.2%	0.3%	0.3%	0.7%	0.5%	0.3%	0.1%
18	0.0%	0.2%	0.1%	1.7%	2.7%	1.1%	1.2%	2.2%	8.8%	5.3%	0.0%	0.0%
19	0.1%	0.1%	0.0%	7.4%	11.3%	9.2%	9.8%	6.0%	0.5%	0.0%	0.0%	0.2%
20	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.2%
21	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 24. DEP Tranche 1: Final Incremental Load Following Targets

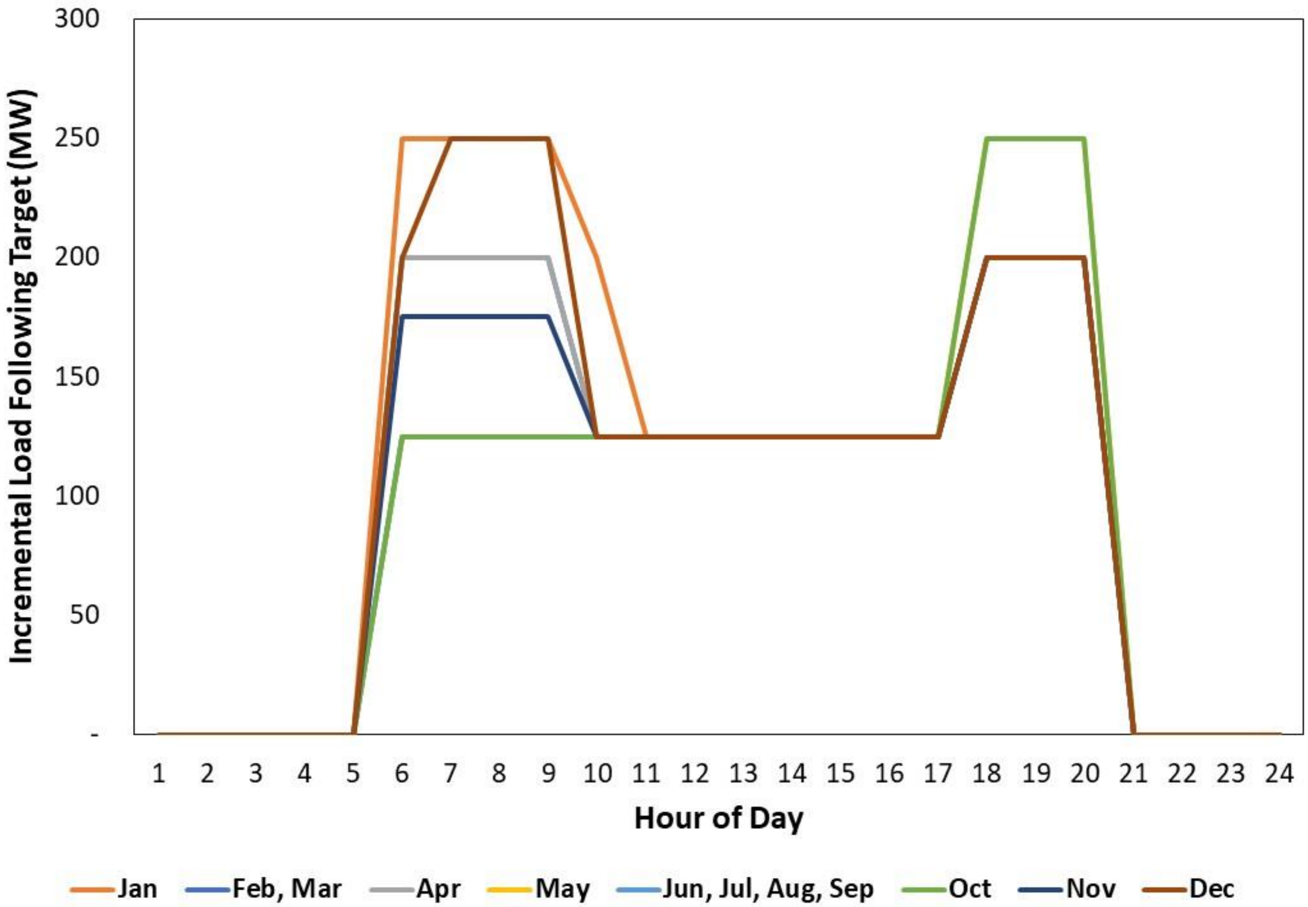
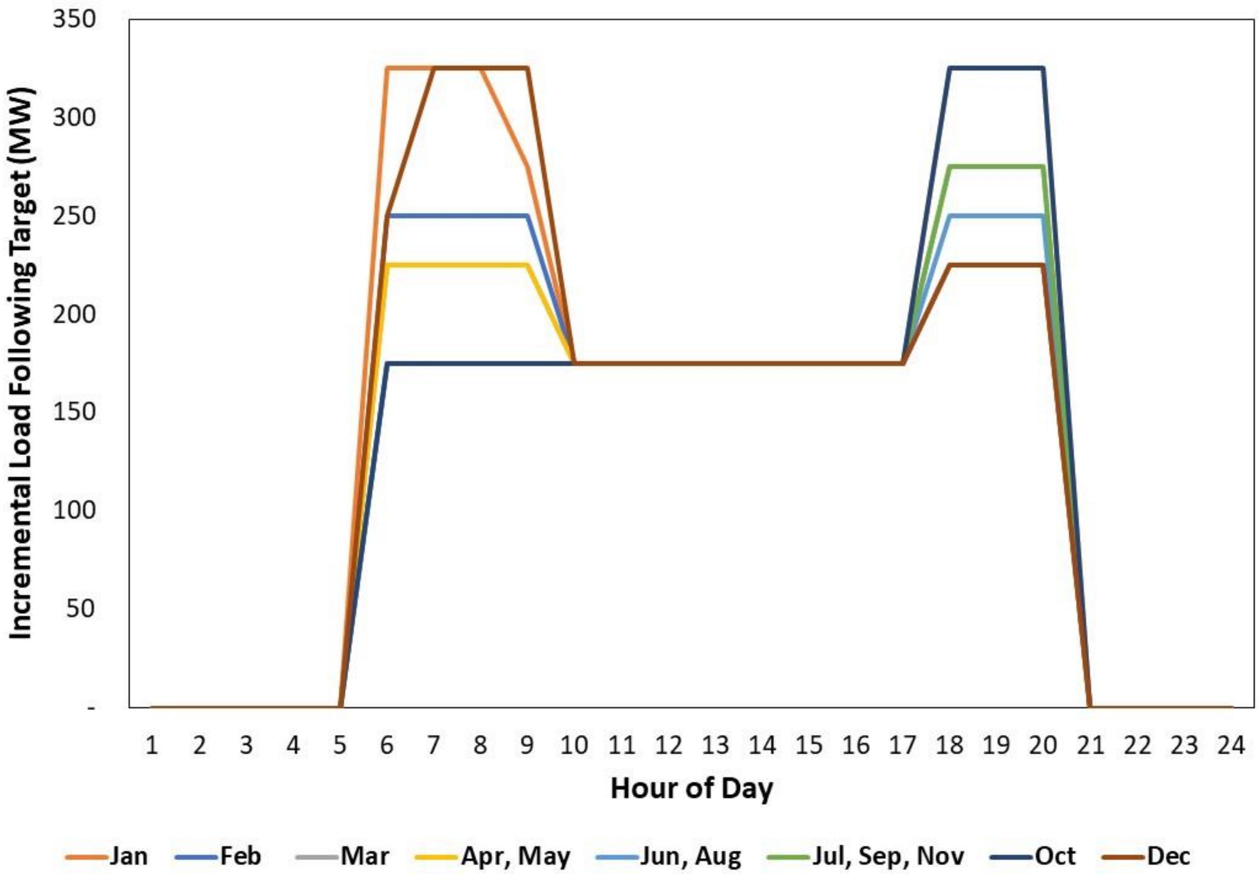


Figure 25. DEP Tranche 2: Final Incremental Load Following Targets for Commitment



IV. Island Results

Tables 11 and 12 show the results of the island cases for both DEC and DEP. As solar generation is added, net load volatility increases causing flexibility excursions to increase if nothing is done to mitigate them. To reduce the excursions, additional load following as presented in the previous sections are added into the model. This higher load following target causes an increase in costs. For DEC, the results show that as solar increases from 0 MW to 1,873 MW, 16 MW on average across daytime hours of additional load following is required to maintain the same number of flexibility excursions that occurred in the no solar base case. The total costs of the additional load following across the incremental 1,873 MW of solar generation is calculated as $1.18 /MWh. As Tranche 2 is added to the analysis, which includes 2,738 MW of solar, 26 MW of additional load following on average across daytime hours is required compared to the no solar base case. The total costs of the additional load following for the incremental tranche 2 solar is $1.63/MWh while the total average cost of the additional load following for tranche 2 solar is $1.33/MWh. The incremental cost represents the integration cost of the solar capacity that is added between Tranche 1 and Tranche 2. Similar patterns are seen in the DEP and the results are outlined in Table 12. Tranche 1, which assumes 3,590 MW of solar requires 49 MW of additional load following on average across daytime hours which results in $1.49/MWh. Tranche 2, which assumes 4,392 MW of solar capacity requires 65 MW of additional load following on average across daytime hours which results in a total cost of load following of $1.62/MWh. The incremental cost of Tranche 2 is $2.11/MWh.

Table 11. DEC Island Results

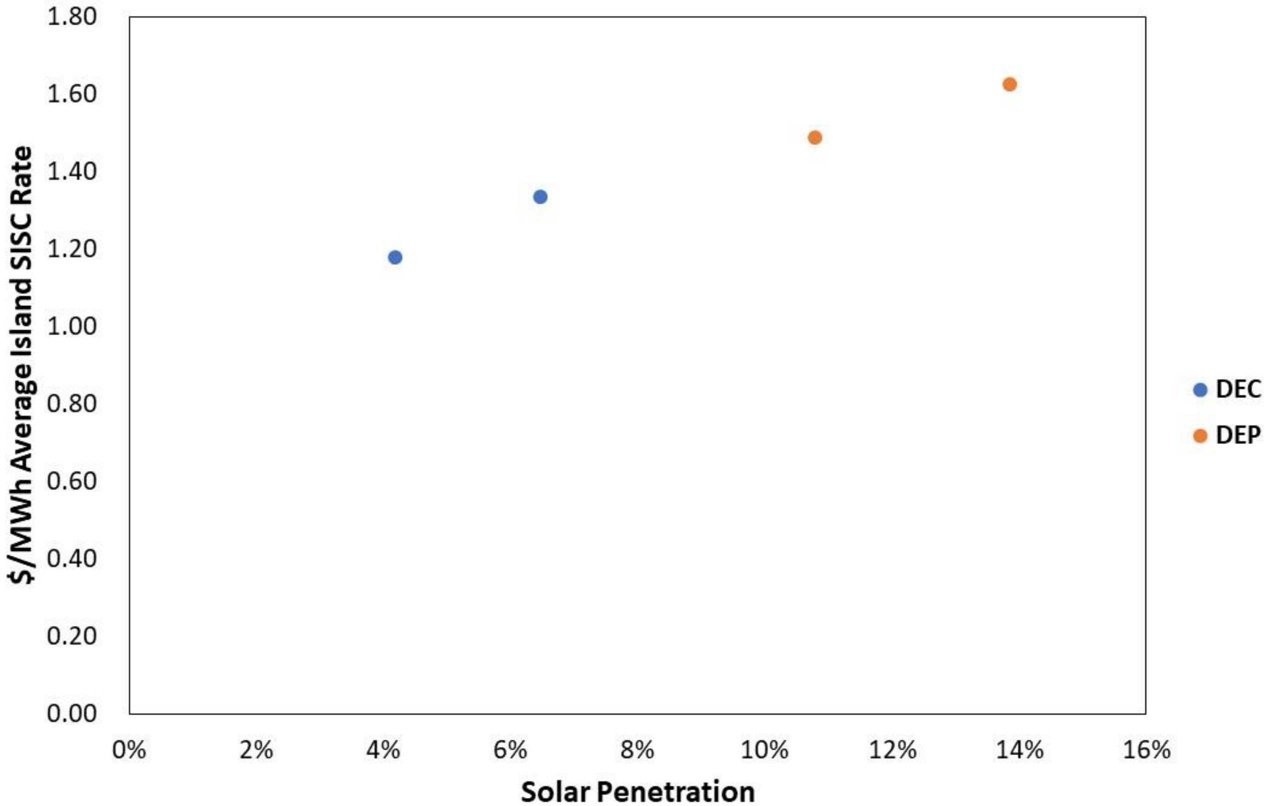
	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	1,873	2,738
Flexibility Violations (Events Per Year)	2.94	2.94	2.94
Average SISC ($/MWh)	0	1.18	1.33
Incremental SISC ($/MWh)	0	1.18	1.63
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	16	26
Additional Curtailment Due to Solar and Load Following (MWh)	0	7,395	26,763
Additional Curtailment Only Due to Additional Load Following (MWh)	0	2,436	4,292
Solar Generation (MWh)	0	4,209,236	6,496,508
Percentage of Solar Generation Curtailed (%)	0	0.18%	0.41%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.058%	0.066%

Table 12. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	3,590	4,392
Flexibility Violations (Events Per Year)	1.47	1.47	1.47
Average SISC ($/MWh)	0	1.49	1.62
Incremental SISC ($/MWh)	0	1.49	2.11
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	49	65
Additional Curtailment Due to Solar and Load Following (MWh)	0	486,539	1,063,478
Additional Curtailment Only Due to Additional Load Following (MWh)	0	17,383	26,111
Solar Generation (MWh)	0	7,498,434	9,627,651
Percentage of Solar Generation Curtailed (%)	0	6.49%	10.77%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.23%	0.27%

Figure 26 shows the island average SISC as a function of solar penetration for both DEC and DEP.

Figure 26. Average SISC as a function of Solar Penetration



V. Combined (JDA Modeled) Results

The combined (JDA Modeled) results model the two DEC and DEP balancing areas with unlimited transmission capability between them, which is consistent with the 2023 Resource Adequacy Study.

In these simulations, the realized load following additions determined in the island case were targeted for the combined case except now economic transfers can be made on a 5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility.

The results are shown below in Table 13 for both Tranche 1 and 2. As expected, when modeling the Combined case, the cost of load following goes down and for Tranche 1, the total costs decrease from 16 million dollars to 14.9 million dollars. This benefit is then allocated across the Companies to develop a lower SISC rate for each Company. Astrapé along with the TRC and the Companies in the 2021 Study determined it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis.[7] The load following cost is the total production cost increase divided by the additional 10-minute load following reserves that are increased. This results in average and incremental SISC values assuming the benefit of the JDA as expressed at the bottom of Table 13. The average and incremental results are the same for Tranche 1 since it is the first tranche of solar studied. For DEC Tranche 2, the average SISC is $1.09/MWh and incremental SISC is $1.46/MWh. Similarly for DEP Tranche 2, the average SISC is $1.62/MWh and the incremental SISC is $2.11/MWh.

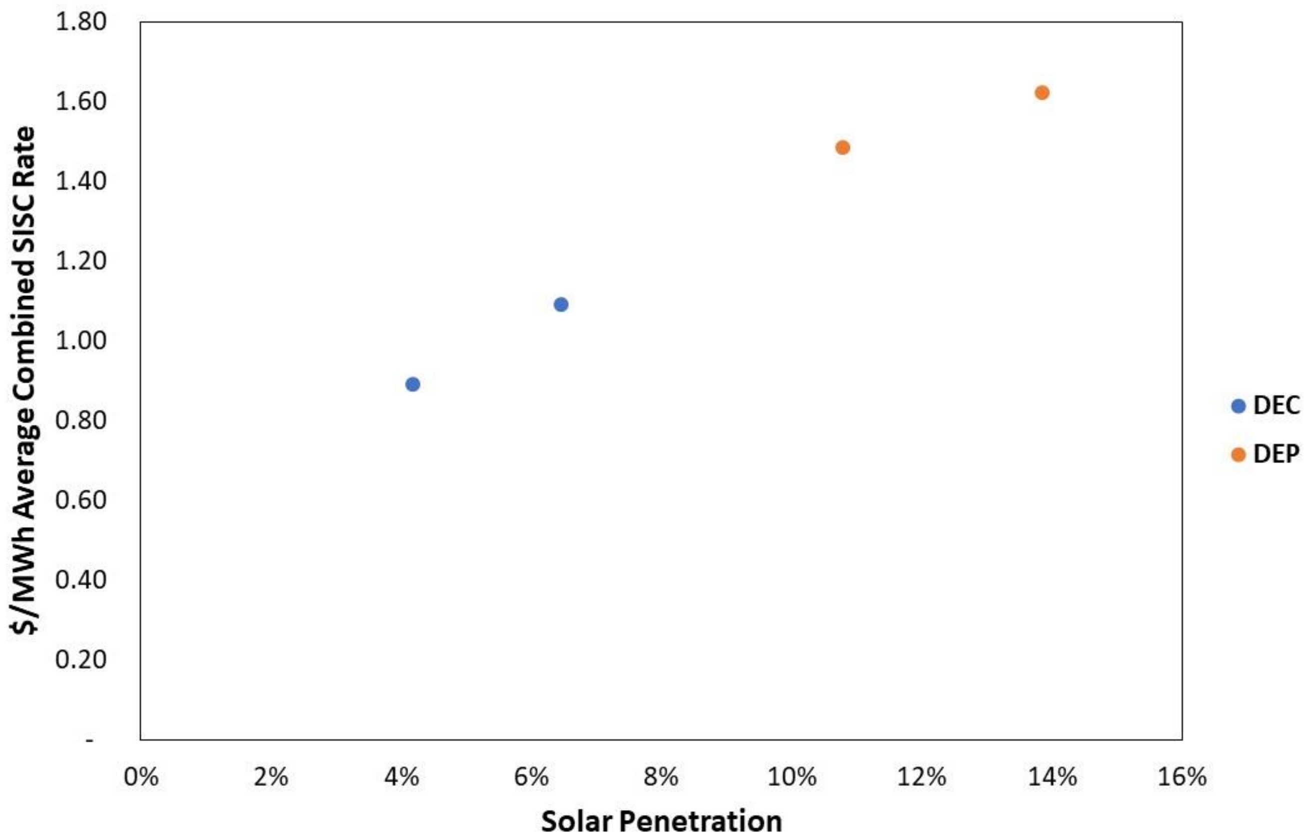
[7] As part of the allocation process, the DEP average SISC for the combined JDA case was capped at its island case SISC and total production costs of the combined JDA were maintained.

Table 13. Combined (JDA Modeled) Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	1,873	3,590	5,463	2,738	4,392	7,130
Solar Generation (MWh)	4,209,236	7,498,434	11,707,670	6,496,508	9,627,651	16,124,160
Island 10-Minute Load Following Reserves Needed (Average Over Daily 16 Hours) (MW)	16	49	65	26	65	91
Island 10 Min Load Following Cost Rate ($/MWh)	52.02	39.12	39.24	58.00	40.92	42.82
Island Integration Costs ($)	4,952,287	11,138,582	16,090,868	8,672,829	15,624,243	24,297,063
Average Island SISC ($/MWh)	1.18	1.49	1.27	1.33	1.62	1.41
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	39.24	39.24	39.24	42.82	42.82	42.82
Combined (JDA Modeled) Integration Costs ($)	3,748,345	11,138,582	14,886,926	7,094,647	15,624,234	22,718,881
Average SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.09	1.62	1.41
Incremental SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.46	2.11	1.77

Figure 27 shows the average SISC for both tranches for the Combined Cases as a function of solar penetration.

Figure 27. Average Combined SISC Rates for Tranche 1 and 2



Lastly Table 14 shows the curtailment in the combined JDA case at the different solar levels. The table breaks up the curtailment into total curtailment from the no solar cases and into a category showing what portion of that curtailment occurred due solely to the load following increase. In the combined (JDA Modeled) case the overall solar curtailment is 0.07% for Tranche 1 and 0.56% for Tranche 2. Overall, low levels of curtailment take place in the Combined (JDA Modeled) case and are driven by the significant pump storage on the DEC system paired with additional battery capacity in both DEC and DEP.

Table 14. Combined (JDA Modeled) Curtailment

	Tranche 1	Tranche 2
Renewable Capacity (MW)	5,463	7,130
Solar Penetration (%)	6.89%	9.49%
Renewable (MWh)	11,707,670	16,124,160
Additional Curtailment from No Solar Case (MWh)	8,499	89,913
Additional Curtailment from No Solar Case (% of Total Solar Gen)	0.072%	0.56%
Portion of Additional Curtailment Only Due to Additional Load Following (MWh)	961	6,799
Portion of Additional Curtailment Only Due to Additional Load Following (% of Total Solar Gen)	0.008%	0.042%

VI. Summary

As more solar is added to the DEC and DEP systems, additional ancillary services in the form of load following are required to meet load in real time. This Study simulated both the DEC and DEP systems to determine the amount of load following that was needed to maintain the same level of flexibility excursions the system experienced before the solar was added. The SISC was then calculated based on the costs of the additional load following. This was conducted for both DEC and DEP each as islands and then as a combined analysis, which assumes the JDA was used to economically provide the load following requirements. The values in the Study provide information for the Companies to propose a SISC for their Avoided Cost Filing.

VI. Appendix

Similar to the 2021 Study, a third tranche was also simulated representing 3,461 MW in DEC and 5,299 MW in DEP. This tranche has no impact on rates being set in the Companies Avoided Cost filing. The results for the island and combined case are shown in Table A.1 for informational purposes.

Table A.1. Tranche 3 Results

	DEC Tranche 3	DEP Tranche 3
Total Solar (MW)	3,461	5,299
Flexibility Violations (Events Per Year)	2.94	1.47
Average SISC - Island ($/MWh)	1.92	1.76
Incremental SISC - Island ($/MWh)	3.89	2.20
Realized 10 Min Load Following Reserves **(Average MW Over Solar Hours Assuming 16 Hours)** (MW)	36	83
Additional Curtailment Due to Solar and **Load Following - Island** (MWh)	77,126	2,000,445
Additional Curtailment Only Due to Additional **Load Following - Island** (MWh)	17,947	44,460
Solar Generation (MWh)	8,443,422	12,065,170
Percentage of Solar Generation Curtailed - Island (%)	0.913%	16.58%
Percentage of Solar Generation Curtailed Due to Additional **Load Following - Island** (%)	0.21%	0.37%
Combined (JDA Modeled) Tranche 3 Average SISC ($/MWh)	1.55	1.76