STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1247

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Approval of CPRE Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-110.8 and NCUC Rule R8-71	))))	ORDER APPROVING CPRE RIDER AND CPRE PROGRAM COMPLIANCE REPORT

BEFORE: Commissioner Kimberly W. Duffley, Presiding; Chair Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES:

For Duke Energy Carolinas, LLC:

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E. Brett Breitschwerdt, McGuireWoods LLP, P.O. Box 27507, Raleigh, North Carolina 27611

For the Carolina Industrial Group for Fair Utility Rates III:

Christina D. Cress, Bailey & Dixon, LLP, P.O. Box 1351, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc:

Marcus W. Trathen and Craig D. Schauer, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, P.O. Box 1800, Raleigh, NC 27602

For the North Carolina Sustainable Energy Association:

Peter H. Ledford and Benjamin Smith, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Layla Cummings, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: Pursuant to N.C. Gen. Stat. § 62-110.8(g) and Commission Rule R8-71, the Commission is required to conduct an annual proceeding to review costs incurred or anticipated to be incurred by an electric public utility to comply with the Competitive Procurement of Renewable Energy (CPRE) Program pursuant to N.C.G.S. § 62-110.8 and an annual compliance report filed by the electric public utility pursuant to Rule R8-71(h).

On February 23, 2021, Duke Energy Carolinas, LLC (DEC), filed an application pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71 for approval of its 2020 CPRE Program Compliance Report (Compliance Report) and CPRE Cost Recovery Rider, along with the direct testimony and exhibits of Janet A. Jones, Rates and Regulatory Manager, and Phillip H. Cathcart, Compliance Manager with the Business & Compliance Department. The testimony of witness Cathcart included the Compliance Report as Exhibit No. 1.

Petitions to intervene were filed by (1) the Carolina Utility Customers Association, Inc. (CUCA), on April 5, 2020; (2) the North Carolina Sustainable Energy Association (NCSEA) on April 8, 2021; and (3) the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) on April 22, 2021. By various orders, the Commission granted these petitions to intervene. Furthermore, the intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On March 18, 2021, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice in which the Commission set this matter for hearing; established deadlines for the submission of petitions to intervene, the filing of intervenor testimony, and DEC's rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

On May 3, 2021, DEC filed the supplemental testimony and exhibits of witnesses Jones and Cathcart. The supplemental testimony of witness Jones presented revised rates reflecting the impacts related to updates to numbers presented in her direct exhibits and workpapers, which resulted in lower customer rates for the billing period. In accordance with the requirement of Commission Rule R8-71(j)(1), witness Jones addressed DEC's proposal to recover costs on a market basis for DEC-owned facilities. The supplemental testimony of witness Cathcart provided an update on the status of Tranche 2 winning projects and presented revised commercial operation dates for Tranche 1 winning projects.

On May 13, 2021, the Public Staff filed the affidavit of R. Tyler Allison and the direct testimony of Jeff Thomas recommending approval of DEC's revised rates set forth in DEC's supplemental testimony and agreeing with DEC that market-based cost recovery is appropriate for DEC-owned facilities in lieu of cost-of-service-based (COS-based) recovery. Public Staff witness Thomas further recommended that the Commission require DEC to seek market-based recovery after the initial term.

On May 21, 2021, DEC filed the rebuttal testimony of witness Jones acknowledging the Public Staff's recommendation to approve DEC's rates as proposed in its supplemental testimony. Witness Jones further testified that it is unnecessary to resolve the issue of postterm recovery for DEC-owned facilities at this time.

On May 24, 2021, the Public Staff filed a motion to excuse all Public Staff and DEC witnesses.

On May 25, 2021, the Commission issued an Order Excusing Witnesses, Accepting Testimony, Canceling Expert Witness Hearing, and Requiring Proposed Orders.

On May 25, 2021, and May 27, 2021, DEC filed affidavits of publication indicating that the initial and second public notice had been provided in accordance with the Commission's procedural order.

On May 27, 2021, DEC filed a motion to cancel the Public Hearing, stating that no members of the public had registered to speak at the hearings. On May 28, 2021, the Commission issued an Order Cancelling Public Hearings.

On June 30, 2021, DEC and the Public Staff filed a joint proposed order. The Public Staff and DEC also separately filed an additional finding of fact on the issue of postterm cost recovery for DEC-owned facilities.

Based upon DEC's verified application, the testimony, workpapers, and exhibits received into evidence and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEC is a duly organized limited liability company existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the Commission's jurisdiction as a public utility. DEC is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-110.8 and Commission Rule R8-71.

2. The test period for purposes of this proceeding is the 12-month period beginning on January 1, 2020, and ending on December 31, 2020 (test period or EMF period). The billing period for this proceeding is the 12-month period beginning on September 1, 2021, and ending on August 31, 2022.

3. In DEC's application, direct testimony, and supplemental testimony (including workpapers and exhibits), it identified system level costs and revenues attributable to the test period as follows: $55,105 in charges for purchased and generated power; $488,499 in CPRE Program implementation costs; $767,203 in revenues; and

$2,254,000 in onetime revenues associated with contract fees collected from CPRE Program market participants (MPs) in 2020. Of these system level charges and revenues, DEC proposed to credit $403,378, the difference between CPRE Program costs allocated to the North Carolina retail customers and CPRE Program rider revenues collected from the North Carolina retail customer classes in the test period, back to North Carolina retail customers. Also, DEC proposed a credit of $1,508,565, the North Carolina retail customers' allocable share of the above-mentioned onetime system revenues associated with contract fees collected from MPs in 2020.

4. DEC's purchased or generated power costs and the CPRE implementation charges for the test period were reasonably and prudently incurred.

5. The North Carolina retail jurisdictional allocation factors related to the capacity and energy components of purchased and generated power costs incurred during the test period in this proceeding were 67.09% and 66.90%, respectively. The capacity component was based on the 2019 production plant allocator, and the energy component was based on test period sales. Similarly, the North Carolina retail class allocation factors related to the capacity and energy components of purchased and generated power costs incurred during the test period in this proceeding were based on the 2019 production plant and test period sales for each class, respectively. The North Carolina retail class allocation factors related to implementation charges incurred during the test period were based on a composite rate calculated as the weighted average of the capacity and energy components of purchased and generated power.

6. The North Carolina retail test period sales used in calculating the EMF rider component are 55,511,864 MWh. The adjusted North Carolina retail customer class MWh sales were as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	21,396,039
General Service/Lighting	22,718,144
Industrial	11,397,681
Total	55,511,864

7. In DEC's supplemental testimony, including exhibits, it requested $15,205,457 in billing period charges anticipated to be incurred for purchased and generated power and ongoing implementation costs.

8. The North Carolina retail jurisdictional allocation factors related to the capacity and energy components of purchased and generated power costs anticipated to be incurred during the billing period in this proceeding are 66.90% and 65.99%, respectively. The capacity component is based on the 2020 peak demand, and the energy component is based on projected billing period sales. Similarly, the North Carolina retail class allocation factors related to the capacity and energy components of purchased and generated power costs anticipated to be incurred during the billing period in this proceeding are based on the 2020 peak demand and projected billing period sales for each class, respectively. The North Carolina retail class allocation factors related to

implementation charges anticipated to be incurred during the billing period are based on a composite rate calculated as the weighted average of the capacity and energy components of purchased and generated power.

9. The projected billing period sales for use in this proceeding are 57,967,737 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	21,803,077
General Service/Lighting	24,128,419
Industrial	12,036,241
Total	57,967,737

10. DEC's North Carolina retail onetime revenue credits and overrecovery of costs for the test period, or EMF period, amount to $1,911,943, excluding interest and the regulatory fee, as set forth on Jones Revised Exhibit 4. These onetime revenue credits and overrecovery by customer class are $752,156 for the Residential class, $774,038 for the General Service/Lighting class, and $385,749 for the Industrial class.

11. The appropriate EMF rider component to be credited to customers are (0.0035) cents per kWh for the Residential class, (0.0033) cents per kWh for the General Service/Lighting class, and (0.0033) cents per kWh for the Industrial class, including interest related to the overcollection (excluding the regulatory fee).

12. The appropriate North Carolina retail prospective billing period expenses, as adjusted and set forth on Jones Revised Exhibit 3, total $15,205,457. The appropriate prospective billing period expenses for use in this proceeding are $5,943,227 for the Residential class, $6,220,902 for the General Service/Lighting class, and $3,041,327 for the Industrial class.

13. The appropriate monthly prospective rider component to be charged to customers are 0.0273 cents per kWh for the Residential class, 0.0257 cents per kWh for the General Service/Lighting class, and 0.0252 cents per kWh for the Industrial class, excluding the regulatory fee.

14. The appropriate combined monthly EMF rate component and prospective rate component to be collected during the billing period are 0.0238 cents per kWh for the Residential class, 0.0224 cents per kWh for the General Service/Lighting class, and 0.0219 cents per kWh for the Industrial class, excluding the regulatory fee.

15. The increase in costs DEC proposes to recover with its proposed CPRE Program Rider and EMF Rider are within the limit established in N.C.G.S. § 62-110.8.

16. The 2020 CPRE Compliance Report provides adequate information that satisfies the requirements of Commission Rule R8-71(h), and for the reporting period, DEC implemented the CPRE Program in compliance with the requirements of N.C.G.S. § 62-110.8.

17. In the case of the two DEC-owned facilities, the Commission approves the DEC's request to recover costs for the DEC-owned CPRE facilities on a market basis in lieu of cost-of-service recovery. Specifically, DEC will recover the costs associated with these facilities at the $/MWh price at which those facilities bid into CPRE Tranche 1 RFP and were selected by the IA. The issue of postterm recovery is already addressed by Commission Rule R8-71(l)(4); therefore, it is not necessary to further address this issue in the context of this CPRE rider proceeding

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence for this finding of fact is contained in the direct and supplemental testimony and exhibits of DEC witness Jones.

Pursuant to N.C.G.S. § 62-110.8, an electric public utility shall be authorized to recover the costs of all purchases of energy, capacity, and environmental and renewable attributes from third-party renewable energy facilities and to recover the authorized revenue of any utility-owned assets that are procured through an annual rider approved by the Commission and reviewed annually. Commission Rule R8-71 prescribes that unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for purposes of Rule R8-55. The test period for purposes of Rule R8-55 is the 12 months ending December 31. Witness Jones testified that for purposes of this proceeding, DEC's proposed rider includes both an EMF rider component to adjust for the difference in DEC's costs incurred compared to revenues realized during the EMF test period, as well as a rider component to collect costs forecasted to be incurred during the prospective 12-month period over which the proposed CPRE Program rider will be in effect.

DEC's proposed test period is the 12 months beginning on January 1, 2020, and ending on December 31, 2020, and the proposed billing period for the CPRE Program rider is the 12 months beginning on September 1, 2021, and ending on August 31, 2022.

The test period and the billing period proposed by DEC were not challenged by any party. Based on the foregoing, the Commission concludes that DEC used the appropriate test period and billing period in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence for these findings of fact is contained in the direct and supplemental testimony and exhibits of DEC witnesses Jones and Cathcart, the testimony and exhibits of Public Staff witness Thomas, and the affidavit of Public Staff witness Allison.

On Revised Jones Exhibit No. 1, DEC witness Jones identifies $55,105 on a system basis of purchased power costs and authorized revenue for DEC-owned facilities during the EMF period. As stated in the testimony of witness Jones, these costs originate from one DEC-owned facility achieving commercial operation during the EMF period and a second providing precommercial generation during testing. On Jones Exhibit No. 2, DEC witness Jones set forth the per books implementation charges of $488,499 incurred by DEC on a system basis to implement the CPRE Program during the test period.

Revised Jones Exhibit 4 evidences $363,825 in costs incurred during the EMF period that were allocated to the North Carolina retail jurisdiction and $767,203 in CPRE Program rider revenues collected during the EMF period, resulting in an overcollection of $403,378.

Witness Jones also testified that DEC received $2,254,000 in onetime revenues associated with contract fees collected from CPRE Program MPs in 2020. She further testified as to DEC's proposal that North Carolina retail customers be credited with $1,508,565, their allocable share, through the proposed EMF rider component.

DEC witness Cathcart testified regarding DEC's actions to implement the CPRE Program and comply with the CPRE Program requirements of N.C.G.S. § 62-110.8, as described in DEC's CPRE Compliance Report.

Public Staff witness Thomas discussed the system-level expenses sought to be recovered by DEC, but he did not recommend any adjustments to the system-level expenses.

Public Staff witness Allison testified as to the procedures taken by the Public Staff to evaluate whether DEC properly determined its per-books CPRE Program costs and revenues during the test period. Witness Allison did not recommend any adjustments to the proposed EMF rider component. No parties challenged the prudency of the total amount of $1,911,943, which excludes interest, that DEC is requesting to credit back to customers.

The Commission concludes that the $1,911,943 North Carolina retail level overcollection and onetime revenue credits collected by DEC during the EMF period for the CPRE program were reasonably and prudently incurred and are appropriate to be credited back to customers by DEC.

The Commission notes that DEC's CPRE implementation charges of $488,499 include $179,552 of excess Independent Administrator Fees. Pursuant to N.C.G.S. § 62-110.8(d) the CPRE Program must be administered by an independent, third-party administer (Independent Administrator or IA). The IA's "reasonable and prudent administrative and related expenses incurred to implement [the CPRE Program] shall be recovered from market participants through administrative fees levied upon those that participate in the competitive bidding process, as approved by the Commission." N.C.G.S. § 62-110.8(d). Commission Rule R8-71(d)(10) provides that:

> The Independent Administrator's fees shall be funded through reasonable proposal fees collected by the electric public utility. The electric public utility shall be authorized to collect proposal fees up to $10,000 per proposal to defray its costs of evaluating the proposals. In addition, the electric public utility may charge each participant an amount equal to the estimated total

> cost of retaining the Independent Administrator divided by the reasonably anticipated number of proposals. To the extent that insufficient funds are collected through these methods to pay of the total cost of retaining the Independent Administrator, the electric public utility shall pay the balance and subsequently charge the winning participants in the CPRE RFP Solicitation.

DEC witness Cathcart testified that for Tranche 2 of the CPRE Program, DEC and Duke Energy Progress, LLC (DEP, and collectively, Duke), elected to structure program fees pursuant to Commission Rule R8-71(d)(10) as follows. First, all proposals were charged a Proposal Fee of $500/MW, based on the facility's nameplate capacity, up to a maximum of ten thousand dollars ($10,000). Duke collected a total of $519,765 in Proposal Fees to off-set the IA's fees. Second, Winners' Fees were collected on a pro-rata basis from each winning proposal up to a predetermined total cap of $1,000,000. The Tranche 2 Winners' Fees were determined upon conclusion of the RFP and were calculated based on the amount of the IA's costs that were not recovered through the Proposal Fees. The Winners' Fees were then allocated among all winning proposals selected by both DEC and DEP on a pro-rata, per-MW basis. Duke collected a total of $1,000,000 (the maximum allowable amount) from Winners' Fees. In total, Duke collected $1,519,765 in Tranche 2 of CPRE Program fees to fund the IA's associated fees.

DEC witness Cathcart also testified that for Tranche 2 of the CPRE Program, the IA's actual expenses were approximately $1,700,000, which exceeded the total Tranche 2 CPRE Program fees by approximately $242,000. Further, during the test period, the IA also incurred and submitted expenses of approximately $117,000 related to Tranche 1 of the CPRE Program. In total, the excess IA fees for the test period were $359,000, which Duke split equally between DEC and DEP. For the purposes of this proceeding, DEC seeks to recover its pro-rata share of the excess IA fees, $179,552 in total. DEP seeks recovery of its pro-rata share through its annual CPRE rider proceeding, Docket No. E-2, Sub 1275, which is currently pending before the Commission.

Public Staff witness Thomas testified that in DEC's prior CPRE Rider proceeding, Docket No. E-7, Sub 1231 (Sub 1231), DEC also sought recovery of IA fees in excess of the amount collected from MPs via the Tranche 1 Program fees. Witness Thomas and DEC witness Cathcart both noted that in the Sub 1231 proceeding, DEC agreed to raise the cap on Winners' Fees in subsequent tranches from $500,000 to $1,000,000 to help ensure that the IA's fees were recovered from MPs. Witness Thomas also testified that, in order to provide MPs with certainty regarding Winners' Fees, the $1,000,000 cap was stated in the Tranche 2 RFP. Finally, witness Thomas stated that the $1,000,000 cap was believed to be sufficient to prevent a similar underrecovery in the future.

Witness Cathcart and witness Thomas each explained that from Tranche 1 to Tranche 2 there was an unanticipated, significant reduction in the number of proposals submitted that resulted in a corresponding reduction in Proposal Fees. Witness Cathcart also testified that a number of factors caused the IA's fees to exceed estimates, including extensive unanticipated stakeholder processes and reporting obligations.

Witness Thomas also offered testimony on two disputes arising out of Tranche 1 of the CPRE Program: (1) Stanly Solar, LLC (Stanly), Docket No. SP-9590, Sub 0, and (2) Orion Renewable Resources, LLC (Orion), Docket No. SP-13695, Sub 1. Witness Thomas noted that IA fees related to these disputes are included in the current proceeding and anticipates that next year's CPRE Rider proceeding will also include fees incurred related to these disputes. Witness Thomas expressed concern about the potential for the IA to incur significant costs associated with the Orion dispute.

Finally, witness Thomas testified that the reduction of the amount covered through Proposal Fees in Tranche 2 plus the IA's fees related to the above-described disputes arising out of the Tranche 1 CPRE process, resulted in the excess IA fees DEC seeks to recover here. Notwithstanding the foregoing, witness Thomas testified that DEC provided a reasonable explanation for why the IA's fees exceeded the fees recovered from MPs and did not recommend that the Commission disallow any of the excess IA fees.

The Commission has carefully considered the excess IA fees described herein and the explanations of DEC and the Public Staff. For the purpose of this proceeding, the Commission accepts the Public Staff's recommendations that DEC has presented a reasonable basis for why the IA's fees exceeded the fees recovered from MPs and that the Commission allow DEC to recover the excess IA fees incurred during the test period. The Commission further notes that relative to standard offer Public Utility Regulatory Policies Act (PURPA) contracts at avoided costs, Tranche 1 of the CPRE is projected to save ratepayers an estimated $261,000,000 over 20 years,[1] and Tranche 2 is projected to save ratepayers an estimated $98,700,000 over 20 years.[2] For these reasons, the Commission determines that the excess IA fees that DEC seeks to recover in this proceeding are in the public interest, thus warranting a deviation from the requirements of N.C.G.S. § 62-110.8(d) and Commission Rule R8-71(d)(10), which is consistent with the Commission's authority pursuant to N.C.G.S. § 62-110.8(h)(5) and Commission Rule R8-71(i)(2).

The CPRE Program continues to evolve through lessons learned with each Tranche; however, going forward, the Commission stresses its firm expectation that CPRE Program fees for future tranches will be structured to ensure that all IA fees are recovered solely from MPs as is contemplated by N.C.G.S. § 62-110.8(d) and Commission Rule R8-71(d)(10). Toward this end, the Commission notes that in the CPRE Program Dockets, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, Duke stated its intent to file a new CPRE Program Plan on September 1, 2021, in the pending Integrated Resource Plan proceeding (E-100, Sub 165), which will include plans for a potential upcoming Tranche 3 procurement. The Commission finds it appropriate to require Duke to confer with the IA and the Public Staff and to include in its upcoming CPRE Program Plan (1) the IA's proposed scope of work to implement Tranche 3, (2) an IA fee estimate

[1] Tranche 1 Final Report of the Independent Administrator at 1, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (July 23, 2019).

[2] Tranche 2 Final Report of the Independent Administrator at 1, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (Feb. 12, 2021).

based on the proposed scope of work, and (3) a proposed Tranche 3 program fee structure designed to recover all Tranche 3-related IA fees from Tranche 3 MPs.

Finally, the Commission shares the Public Staff's concern about continuing IA fees associated with Tranches 1 and 2, particularly the disputes noted herein. Therefore, the Commission finds good cause to require that the Public Staff receive copies of all IA invoices at the time that they are submitted to Duke for payment so that the Public Staff is able to carefully review the excess charges to ensure that they are justified, reasonable, prudent, and in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the supplemental testimony and exhibits of DEC witness Jones and the affidavit of Public Staff witness Allison.

In Revised Jones Exhibit 4, DEC witness Jones provided DEC's North Carolina retail jurisdictional allocation factors, including 67.09% for capacity-related costs and 66.90% for energy-related costs. The CPRE Program implementation charges allocation factor, which is a composite allocation factor based on the weighted average of capacity and energy purchases for purchased power costs, is 66.93%. Pursuant to the affidavit of Public Staff witness Allison, the capacity allocator reflects the production plant allocator from DEC's 2019 Cost of Service study and is consistent with DEC's fuel filing. The composite implementation charges allocation factor also reflects the production plant allocator from DEC's 2019 Cost of Service study and is consistent with DEC's fuel filing.

No other party presented evidence on the appropriateness of the North Carolina retail jurisdictional allocation factors.

The Commission concludes that the 67.09% allocation factor for capacity-related costs and the 66.90% allocation factor for energy-related costs are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of DEC witness Jones.

Jones Workpaper No. 4, provides DEC's North Carolina test period retail sales of 21,396,039 MWh for the Residential class, 22,718,144 MWh for the General Service/Lighting class, and 11,397,681 MWh for the Industrial class. No other party presented evidence on the appropriateness of test period North Carolina retail sales.

The Commission concludes that the test period North Carolina retail MWh sales proposed by DEC for purposes of calculating the EMF billing factors are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-8

The evidence supporting these findings of fact is contained in the direct and supplemental testimony and exhibits of DEC witness Jones and Public Staff witness Thomas.

Jones Exhibit No. 2 and Jones Revised Exhibit No. 3 present DEC's projected North Carolina retail allocated CPRE costs of $15,205,457 in the billing period, as well as the allocation of the system costs to the North Carolina retail jurisdiction and the North Carolina retail customer classes. DEC used the 2020 peak demand jurisdictional allocation factor of 66.90% for capacity costs and the projected billing period sales jurisdictional allocation factor of 65.99% for energy costs for its allocation of CPRE purchased and generated power costs.

Public Staff witness Thomas discussed the CPRE costs estimated for the billing period but did not recommend any adjustments. No other party presented evidence on the appropriateness of DEC's proposed billing period charges anticipated to be incurred or the allocation of these costs.

The Commission concludes that DEC's North Carolina retail allocated charges of $15,205,457 anticipated to be incurred during the billing period for purchased and generated capacity and energy and ongoing implementation costs are appropriate for use in this proceeding. The Commission further concludes that the use of 66.90% for the capacity component and 65.99% for the energy component to allocate system-level CPRE purchased and generated power costs to the North Carolina retail jurisdiction is appropriate for use in this proceeding, and that the use of peak demand and energy sales, respectively, to allocate North Carolina retail jurisdictional capacity and energy costs to the customer classes is appropriate for use in this proceeding. Further, the Commission concludes that the use of a composite rate for the allocation of North Carolina retail implementation costs to the North Carolina retail customer classes is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of DEC witness Jones.

In Revised Exhibit No. 3, DEC witness Jones provided DEC's projected billing period sales of 21,803,077 MWh for the Residential class, 24,128,419 MWh for the General Service/Lighting class, and 12,036,241 MWh for the Industrial class. Witness Jones further testified that the rate per customer class for purchased and generated power is determined by dividing the sum of the billing period costs allocated to the class by the forecast billing period MWh sales for the customer class. Similarly, the rate per customer class for implementation costs is determined by dividing the sum of the billing period costs allocated to the class, using a composite rate determined in the purchased and generated power calculation, above, by the forecast billing period MWh sales for the customer class.

The Public Staff witnesses did not propose any adjustments to the projected billing period sales amounts used in this proceeding. No other party presented evidence on the appropriateness of the projected billing period North Carolina retail sales.

The Commission concludes that DEC's projected billing period sales for North Carolina retail customer classes are as follows: 21,803,077 MWh for the Residential class, 24,128,419 MWh for the General Service/Lighting class, and 12,036,241 MWh for the Industrial class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10-14

The evidence supporting these findings of fact appears in DEC's application, in the direct and supplemental testimony and exhibits of DEC witness Jones, in the testimony and exhibits of Public Staff witness Thomas, and in the affidavit of Public Staff witness Allison.

Revised Jones Exhibit 4 calculates for North Carolina retail customers a total overrecovery of $403,378 in CPRE Program costs for the EMF period and onetime revenue credits of $1,508,565, resulting in a total credit of $1,911,943 before interest. The North Carolina retail customer share of CPRE Program costs for the prospective billing period, as shown through witness Jones Revised Exhibit 3, amounts to a total of $15,205,457.

In testimony, DEC witness Jones and Public Staff witness Thomas presented the components of the proposed Total CPRE Rate as follows, excluding the regulatory fee:

DEC's Rider Request Filed on May 3, 2021 (cents per kWh)			
Customer Class	**EMF Rate Component**	**Prospective Rate Component**	**Total CPRE Rate**
Residential	(0.0035)	0.0273	0.0238
General Service/Lighting	(0.0033)	0.0257	0.0224
Industrial	(0.0033)	0.0252	0.0219

The Public Staff witnesses recommended that these rates be approved. No other party presented evidence on the appropriateness of the rates. Based on the foregoing, the Commission finds good cause to find that DEC's proposed rates are just and reasonable for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony and exhibits of DEC witness Jones and the testimony of Public Staff witness Thomas.

DEC witness Jones testified that N.C.G.S. § 62-110.8(g) and Commission Rule R8-71 limits the annual increase in CPRE Program-related costs recoverable by an electric public utility to 1% of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year. Witness Jones testified that the increase in aggregate costs DEC seeks to recover in this proceeding is less than the statutory maximum.

Public Staff witness Thomas similarly concluded that the costs DEC seeks to recover are less than 1% of DEC's total North Carolina retail jurisdictional gross revenues for 2020.

For the reasons stated herein, the Commission concludes that the costs DEC seeks to recover in this proceeding are not in excess of the cost cap established by N.C.G.S. § 62-110.8(g).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of DEC witness Cathcart, including the CPRE Compliance Report, and the testimony and exhibits of Public Staff witness Thomas.

The testimony of DEC witness Cathcart and the 2020 CPRE Compliance Report, which accompanied his testimony, detail DEC's actions to implement the CPRE Program requirements of N.C.G.S. § 62-110.8 in collaboration with the IA. The 2020 CPRE Compliance Report includes all of the information required by Commission Rule R8-71(h), including a description of the CPRE Program solicitation undertaken by DEC during the reporting year, the avoided cost rates applicable to Tranche 2, confirmation that all renewable energy resources procured through Tranche 2 were priced at or below avoided costs, certification by the IA that all public utility and third-party proposal responses were evaluated under the published CPRE Program methodology, and that all proposals were treated equitably in Tranche 2 during the reporting year.

The IA's Final Report for Tranche 2 (Tranche 2 Final Report) is included as Appendix A to the 2020 CPRE Compliance Report and provides substantial details regarding the Tranche 2 process and outcome. DEC was ultimately able to procure ten projects totaling 589 MW at prices below the avoided cost cap. The Tranche 2 Final Report also recommend improvements for future CPRE tranches.

Public Staff witness Thomas testified that the 2020 CPRE Compliance Report provides adequate information that satisfies the requirements of Commission Rule R8-71(h). No other party presented evidence on this issue.

In light of the testimony received, the Commission concludes that the 2020 CPRE Compliance Report provides adequate information that satisfies the requirements of Commission Rule R8 71(h), and for the reporting period, DEC implemented the CPRE Program in compliance with the requirements of N.C.G.S. § 62-110.8.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO.17

The evidence supporting this finding of fact is contained in DEC's Application, the direct, supplemental, and rebuttal testimony of DEC witness Jones, and the direct testimony of Public Staff witness Thomas.

The CPRE Rider rates proposed by DEC in its application included costs for certain DEC-owned facilities that were selected as winning bidders in CPRE Tranche 1. DEC proposed that cost recovery for the DEC-owned facilities be established on a market basis in lieu of cost-of-service for the full 20-year CPRE term. Specifically, the costs associated with DEC-owned CPRE facilities were included in the CPRE Rider rates at the price at which those facilities bid into the Tranche 1 RFP and were selected by the IA as winning projects. No party to this proceeding has contested this form of cost recovery, and Public Staff witness Thomas supported DEC's proposal to recover costs on a market basis in lieu of cost-of-service recovery.

In supplemental testimony, witness Jones further testified that DEC's recommendation for recovery on a market basis for these two particular solar facilities is not necessarily representative of the optimal outcome for customers for future DEC-owned solar facilities selected through CPRE. Given the postterm cost uncertainty that comes with market-based prices, DEC believes a diverse portfolio of market-based and cost-of-service based solar resources better mitigates long-term price risks to customers than an all market-based portfolio by reducing the uncertainty of future costs.

While agreeing with DEC's proposed cost recovery for the DEC-owned facilities, Public Staff witness Thomas further recommends that, in this CPRE rider proceeding, the Commission require that DEC continue to seek market-based recovery of its DEC-owned CPRE facilities after the initial 20-year CPRE term. Witness Jones responded to this issue in rebuttal testimony by asserting that the Commission has already addressed the issue of postterm cost recovery for DEC-owned CPRE facilities. Specifically, Commission Rule R8-71(l)(4) established guidelines with respect to postterm cost recovery options for both DEC-owned and third-party owned CPRE facilities. Furthermore, witness Jones noted that the purpose of this proceeding is to establish the Rider CPRE rates for the billing period that runs through August 31, 2022, and that it is unnecessary at this time to address postterm cost recovery that will not be determined until after 2040. Finally, witness Jones noted that, as stated in the CPRE Tranche 1 and Tranche 2 RFPs, the Company priced its facilities based on the assumption that it would be entitled to continue to receive market-based recovery after the initial CPRE term.

Based on the foregoing, the Commission approves the DEC's proposal to recover its costs for the two DEC-owned facilities selected in Tranche 1 on a market basis in lieu of cost-of-service-based recovery. The Commission's determination in this respect is not dispositive with respect to future similar scenarios and the Commission reserves the right to evaluate in the future whether cost-of-service recovery is more beneficial to customers than market-based cost recovery. It is not necessary or appropriate to further address postterm cost recovery at this time in light of the purpose of this proceeding and the fact that such issues are already addressed by Commission Rules, which speak for themselves.

IT IS, THEREFORE, ORDERED, as follows:

1. That DEC's request to establish a prospective rate component as described herein is approved and that this rider shall remain in effect for a 12-month period beginning on September 1, 2021, and expiring on August 31, 2022;

2. That DEC's request to establish an EMF rate component as described herein is approved and that this rider shall remain in effect for a 12-month period beginning on September 1, 2021, and expiring on August 31, 2022;

3. That DEC shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten days after the date of this Order;

4. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, and DEC shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all three dockets;

5. That DEC's 2020 CPRE Compliance Report is hereby approved;

6. That DEC shall confer with the IA and the Public Staff and include in its upcoming CPRE Program Plan (1) the IA's proposed scope of work to implement Tranche 3, (2) an IA fee estimate based on this scope, and (3) a proposed Tranche 3 program fee structure designed to recover all Tranche 3-related IA fees from Tranche 3 MPs; and

7. That Duke shall furnish the Public Staff with copies of all IA invoices upon receipt;

ISSUED BY ORDER OF THE COMMISSION.

This the 17th day of August, 2021.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk