SOUTHERN ENVIRONMENTAL LAW CENTER

Telephone 919-967-1450 | 601 WEST ROSEMARY STREET, SUITE 220
CHAPEL HILL, NC 27516-2356 | Facsimile 919-929-9421



February 12, 2016

*Via Electronic Filing*

Ms. Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: In the Matter of: Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752-MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville
***Docket No. E-2, Sub 1089***

Dear Ms. Mount:

Enclosed for filing in the referenced docket are Comments of MountainTrue and the Sierra Club, including Attachments 1-3. By copy of this letter, I am serving all parties of record on the service list.

Please let me know if you have any questions about this filing.

Sincerely,

s/ Robin G. Dunn
Administrative Legal Assistant
N.C. Certified Paralegal

RGD
Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1089

| | | |
|---|---|---|
| In the Matter of:<br><br>Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752-MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville | )<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>) | COMMENTS OF MOUNTAINTRUE AND THE SIERRA CLUB |

PURSUANT TO the *Order on Procedure for Accepting Comments of the Parties* issued by the North Carolina Utilities Commission ("Commission") on January 22, 2016, intervenors MountainTrue and the Sierra Club, through counsel, file these comments, along with the supporting Affidavit of Richard S. Hahn and exhibits thereto.

**INTRODUCTION**

Duke Energy Progress, LLC ("DEP" or "the Company") has applied to build a massive new gas-fired power plant at the site of its Asheville Steam Station. The proposed new 746 MW gas plant would have approximately twice the capacity of the 379 MW coal units that it is proposed to replace. At the outset, it is important to emphasize that MountainTrue and the Sierra Club applaud two of DEP's recent decisions related to energy resources in DEP's Western Region: DEP's decision to retire the existing Asheville coal units in 2020 and DEP's decision to cancel the Foothills Transmission Line project. Unlike those decisions, DEP's current proposal would lock in a long-term commitment to new fossil-fueled generation in Western North Carolina. Yet, as explained in detail in the following comments, DEP has not demonstrated that such a large amount of new gas-fired capacity in the proposed time frame is needed to serve customers in DEP's Western Region ("DEP-W").

In its Application, DEP seeks a Certificate of Public Convenience and Necessity ("CPCN") to construct a 752 MW natural gas-fueled electric generation facility dubbed the "Western Carolinas Modernization Project" (the "Project"). The first phase of the Project would consist of two new 280 MW natural gas-fueled combined cycle units proposed to go into service in 2019 to replace the coal units at the Asheville site when they retire in 2020. DEP has not shown that this amount of gas capacity is needed to serve customers in the proposed timeframe.

In addition, DEP seeks approval for one "contingent" 192 MW natural gas-fueled simple cycle combustion turbine unit that would not go into service until 2023, if ever. In other words, DEP is now seeking Commission authorization not only for the 560 MW of gas capacity it claims it needs in 2019, but also advance permission for an additional 192 MW that the Company may or may not need in 2023. This is simply an overreach, and should be rejected by the Commission.

Finally, in the Application DEP also signals its intent to invest in solar generation that would be subject to a future CPCN application, as well as a potential energy storage facility. Unlike the contingent 192 MW CT unit, however, DEP does not seek approval at this time for those speculative future projects. The Commission should hold DEP to its commitments regarding clean energy development in DEP-W.

As the Commission is aware, North Carolina law prohibits costly overbuilding of unnecessary new power plants. On the record in this proceeding, DEP has not demonstrated that the Project, as proposed, is justified by public convenience and necessity. Accordingly, the Commission should deny the Application. If the Commission does elect to grant a CPCN, however, it should reduce the size of the Project in line with customer needs, and impose conditions to save customers money and promote clean, cost-effective energy resources in DEP-W.

## LEGAL STANDARD

The Commission's decision whether to grant a CPCN for the Project is governed by two main statutes: N.C. Gen. Stat. § 62-110.1 and the recently enacted Mountain Energy Act, N.C. Session Law 2015-110.

### A. The Mountain Energy Act

Session Law 2015-110 establishes an expedited schedule for the Commission's consideration of a CPCN application that meets certain criteria. The Act provides, in pertinent part:

> Notwithstanding G.S. 62-110.1, the Commission shall provide an expedited decision on an application for a certificate to construct a generating facility that uses natural gas as the primary fuel if the application meets the requirements of this section. . . . When the public utility applies for a certificate as provided in this section, it shall submit to the Commission an estimate of the costs of construction of the gas-fired generating unit in such detail as the Commission may require. G.S. 62-110.1(e) and G.S. 62-82(a) shall not apply to a certificate applied for under this section. . . . The Commission shall render its decision on an application for a certificate . . . within 45 days of the date the application is filed if all of the following apply:
>
> (1) The application for a certificate is for a generating facility to be constructed at the site of the Asheville Steam Electric Generating Plant located in Buncombe County.
>
> (2) The public utility will permanently cease operations of all coal-fired generating units at the site on or before the commercial operation of the generating unit that is the subject of the certificate application.
>
> (3) The new natural gas-fired generating facility has no more than twice the generation capacity as the coal-fired generating units to be retired.

MountainTrue and the Sierra Club do not contest that the Application meets the criteria set forth in subsections (1)-(3) of Session Law 2015-110. That does not end the Commission's inquiry, however. The General Assembly, while prescribing an expedited schedule for consideration of this Application, has not mandated a pre-ordained result. The Commission retains the authority to render its own independent decision, and has a range of options from which to choose, in addition to denying or granting the certificate as proposed. For example, as discussed in the following section, the Commission may grant a CPCN for the Project, subject to reasonable modifications or conditions; or may deny the requested CPCN expressly without prejudice to DEP submitting an amended application that complies with the Commission's terms.

Moreover, the traditional "public convenience and necessity" standard that governs the Commission's consideration of an application for a certificate remains intact. While the Mountain Energy Act states that "G.S. 62-110.1(e) and G.S. 62-82(a) shall not apply to a certificate applied for under this section," those provisions relate to the content of the utility's filing and the procedure to be followed by the Commission. The remaining provisions of G.S. § 62-110.1, as well as case law and Commission orders applying those provisions, still apply. In a proceeding under a similar statute mandating an expedited decision on a CPCN for a gas plant, the Commission applied the traditional public convenience and necessity standard established by the statute and interpreted by longstanding case law. *Order Granting Certificate of Public Convenience and Necessity Subject to Conditions*, Docket No. E-2, Sub 960 (October 22, 2009) ("Wayne County Order") at 11.

### B. The Public Convenience and Necessity Standard

N.C. Gen. Stat. § 62-110.1 provides that "no public utility . . . shall begin the construction of any . . . facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service . . . without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction." G.S. § 62-110.1 (a). "The primary purpose of the statute is to provide for the orderly expansion of the State's electric generating capacity in order to create the most reliable and economical power supply possible and to avoid the costly overbuilding of generation resources." *State ex rel. Utils. Comm'n v. Empire Power Co*., 112 N.C. App. 265, 278, 435 S.E.2d 553, 560 (1993). *See also State ex rel. Utils. Comm'n v. High Rock Lake Ass'n*., 37 N.C. App. 138, 140, 245 S.E.2d 787, 790 (1978) (explaining that the purpose of the section is "to help curb overexpansion of generating facilities beyond the needs of the service area").

Our Supreme Court has explained that the public convenience and necessity standard in G.S. § 62-110.1 "is based on an 'element of public need for the proposed service.'" *High Rock Lake Ass'n*., 37 N.C. App. at 140, 245 S.E.2d at 790 (quoting *State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co.*, 267 N.C. 257, 270, 148 S.E.2d 100, 110 (1966)). *Accord Empire Power Co*., 112 N.C. App. at 279-80, 435 S.E.2d at 561 ("before issuing a CPCN, [the Commission] must establish a public need for a proposed generating facility") (citing *In re Duke Power Co.*, 37 N.C. App. 138, 245 S.E.2d 787).

The standard also requires consideration of the cost of a proposed facility. As the *High Rock Lake Court* observed, "it is clear that the purpose of requiring a certificate of public convenience and necessity before a generating facility can be built is to prevent costly overbuilding." 37 N.C. App. at 141, 245 S.E.2d at 790. While Session Law 2015-110 relieved DEP from the obligation to file the detailed cost information normally required by G.S. § 62-110.1(e), it did not remove cost from the Commission's consideration, and in fact provides that the applicant "shall submit to the Commission an estimate of the costs of construction of the gas-fired generating unit in such detail as the Commission may require."

When considering a certificate for a new generating facility, the Commission has recognized that "[t]he standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered." *Order Granting Certificate of Public Convenience and Necessity with Conditions*, Docket No. E-7, Sub 790 (March 21, 2007) ("Cliffside Order") at 10 (citing *State ex rel. Utils. Comm'n v. Casey*, 245 N.C. 297, 302, 96 S.E.2d 8, 12 (1957)). To ensure that the Commission is able to take these facts into account and make an informed decision regarding an application for a CPCN, G.S. § 62-110.1 includes several requirements. The statute directs the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina . . . and [to] consider such analysis in acting upon any petition by any utility for construction." G.S. § 62-110.1(c). In addition, the statute requires the Commission to take into account the certificate applicant's "arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient and economical electric service." G.S. § 62-110.1(d).

Our Court of Appeals has elaborated on the meaning of the public convenience and necessity standard, explaining that it must be read together with our State's policies regarding energy resources: "We read this standard *in pari materia* with N.C.G.S. § 62-2 which contains ten specific policies . . . ." *Empire Power Co*., 112 N.C. App. at 274, 435 S.E.2d at 557. These policies include, among others:

> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs . . . ;
> ***
> (5) To encourage and promote harmony between public utilities, their users and the environment.

G.S. § 62-2 (a)(3a), (5). In the years since *Empire Power Co.* was decided, G.S. § 62-2 has been amended to include additional policies promoting renewable energy and energy efficiency in the State:

> To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:
> a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
> b. Provide greater energy security through the use of indigenous energy resources available within the State.
> c. Encourage private investment in renewable energy and energy efficiency.
> d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

G.S. § 62-2 (a)(10). Thus, the public convenience and necessity standard must be read with reference to our State's policies of promoting clean energy resources. It follows that the standard is inextricably linked to the question whether the certificate applicant has maximized its use of these resources. If not, the standard has not been met.

The burden is on the certificate applicant to show that its proposed generating facility is required by the public convenience and necessity. An applicant's failure to show that public convenience and necessity requires construction of a generating facility is grounds for denial of a certificate or even dismissal of a certificate application. *Empire Power Co*., 112 N.C. App. at 279, 435 S.E.2d at 560-61 (finding that the Commission's dismissal of an application was proper where the forecast of evidence on the issue of need was inadequate).

Finally, when the Commission does grant a certificate, it has the authority to impose conditions where it deems such conditions necessary to ensure compliance with the public convenience and necessity standard. The Commission has exercised this authority in recent proceedings. For example, in granting a CPCN to Duke Energy Carolinas ("DEC") for a new 800 MW coal unit at DEC's Cliffside Steam Station, the Commission attached several conditions—including requirements that DEC retire four existing units at the site; retire additional coal capacity up to 800 MW; invest a certain percentage of its annual revenues in demand-side management and energy efficiency programs and submit those programs for Commission approval, along with specific annual reporting requirements. Cliffside Order at 34-35. *See also, e.g.,* Wayne County Order at 10-11 (attaching conditions to a CPCN for new gas-fired generation, including retirement of existing coal units at the plant site and requiring a plan to retire additional coal generation "reasonably proportionate" to the amount of incremental generation capacity authorized by the CPCN).

## DISCUSSION

### A. DEP Has Not Established That the Project, As Proposed, Is Justified by the Public Convenience and Necessity.

Richard S. Hahn, a principal consultant with Daymark Energy Advisors who has over 40 years of experience in utility matters, was retained to review DEP's Application for the WCMP and provide his analysis and recommendations. As explained in the Affidavit of Richard S. Hahn, Attachment 1 to these comments, Mr. Hahn has identified a number of concerns and issues regarding the Project.

Mr. Hahn's findings, which are incorporated herein by reference, may be summarized briefly as follows:

- DEP has not adequately supported its claim that imports of power into the DEP-W region are constrained by transmission limitations. In other words, whether DEP-W is a legitimate "load pocket" has not been demonstrated on the record in this proceeding.
- The method that DEP used to determine how much local generation is needed to maintain reliability appears to exceed standards set by the National Electric Reliability Corporation ("NERC"), resulting in an overstated capacity need.
- Even if DEP's assertions about import constraints and the need for local generation to maintain reliability are accepted, the capacity of the proposed project is excessive and should be significantly downsized—two new 185 MW

NGCC units and one 100 MW CT unit would provide virtually the same level of local reliability.[1]

- NGCC capacity in the proposed timeframe does not appear to be the best choice to meet customer demand patterns in DEP-W, which would be better matched with peaking generation.
- DEP's system-wide reserve margin of 17%, which was increased from 14.5% based on an incomplete study, results in an increased capacity need of 355 MW and should be re-examined.
- DEP has not adequately analyzed alternatives, such as renewable energy resources, demand-side management, energy efficiency and purchased power, that could eliminate or reduce the need for the Project.

Taken together, these findings lead to a conclusion that DEP has not demonstrated that the Project, as proposed, is justified by public convenience and necessity.

While DEP has kept detailed cost information for the Project confidential, DEP states publicly in the Application that the projected cost of the Project is approximately $1.1 billion. Application at 14. It goes without saying that this enormous price tag would increase customer rates and bills. DEP's own cost exhibit states that the "revenue requirement" to be collected from customers is estimated at $54.5 million, which would raise rates by approximately 1.6%, on average. Confidential Exhibit 3 at 4 (public portions). Accordingly, all alternatives to reduce the size of the Project should have been—and should still be—considered. DEP may attempt to justify building a larger

[1] In light of this finding, DEP's statement that "the need for the 186 MW contingent Asheville CT in 2023 resulted from DEP's decision to cancel the Foothills Transmission Line," Application at 11, does not bear scrutiny.

project than necessary based on the notion of economies of scale, which would reduce the cost per unit of electricity. The Commission should reject this argument, consistent with its pronouncement in a prior CPCN docket that "economies of scale, standing alone, cannot be used to establish [a] need for new generation." Wayne County Order at 7, fn. 4.

Given the accelerated schedule in this proceeding, it was not possible for Mr. Hahn to conduct a detailed analysis of alternatives that could avoid or defer the need for some or all of the new gas capacity proposed by DEP at the Asheville site. It does not appear that DEP has devoted serious consideration to these resource alternatives in conceiving the Project, however. For example, in response to a data request for studies performed in the past five years to estimate the potential amount of technically feasible energy efficiency that could be implemented within DEP's service territory, the Company simply provided a copy of an out-of-date market potential study performed for DEP in 2012.[2] That study, despite employing some flawed assumptions, nonetheless identified cost-effective EE potential amounting to 16% of energy usage across the DEP system. Given that DEP cites the need for reliability during times of peak demand as a key driver of the Project, it is also important to note that the study was limited to energy efficiency, and did not assess the potential for demand response programs that could help to reduce energy usage at times of peak demand.

In light of the purpose of N.C.G.S. § 62-110.1 to "help curb overexpansion of generating facilities beyond the needs of the service area," *High Rock Lake Ass'n.*, 37 N.C. App. at 140, 245 S.E.2d at 790, and "to avoid the costly overbuilding of generation resources," *Empire Power Co.*, 112 N.C. App. at 278, 435 S.E.2d at 560, DEP's request

[2] Attachment 2, excerpt from DEP responses to MountainTrue and Sierra Club First Data Request to Duke Energy Progress, LLC in the subject docket.

for a CPCN for the Project, as proposed, should not be granted until the Company has addressed these analytical flaws in its justification for the Project.

### B. If the Commission Elects to Grant a Certificate to DEP for the Project, As Proposed or As Modified by the Commission, It Should Attach Specific Conditions Necessary to Meet the Public Convenience and Necessity Standard.

When the Commission decides to award a CPCN, it has the authority to impose conditions as necessary to ensure compliance with the public convenience and necessity standard. The Commission has exercised this authority in recent proceedings, as discussed above. If the Commission determines to grant DEP a certificate in this proceeding, it should impose reasonable conditions aimed at saving money for customers, mitigating any environmental harm caused by the Project, and ensuring compliance with our State's policies of promoting clean energy resources like energy efficiency and renewable energy.

1. <u>The Commission Should Order Retirement of Coal Capacity in Addition to the Asheville Units Already Slated for Retirement.</u>

DEP's application discusses retirement of the existing Asheville coal units as part of the WCMP. Application at 11. But DEP has already announced its decision to shutter those units—it is not newly proposing to do so as part of this project. In its Integrated Resource Plan filed on September 1, 2015, DEP stated that "the combined 376 MW Asheville 1 & 2 coal units are planned to be retired no later than January 31, 2020." Duke Energy Progress, North Carolina Integrated Resource Plan (Annual Report) (September 1, 2015) at 14 (filed as Exhibit 1A to the Application). DEP's decision to retire the Asheville coal units was welcome and long overdue, and the Commission should include the retirement of the units as a condition on any certificate granted in this proceeding. Such a condition would be entirely consistent with the Commission's prior decisions on CPCNs. *See, e.g.*, Cliffside Order at 34 (providing that applicant "shall retire existing Cliffside Units 1 through 4 no later than the date of the commercial operation of the one 800-MW unit certificated herein"); Wayne County Order at 11 (requiring applicant to "permanently cease operation of the three coal-fired generating units at its Wayne County facility" upon completion of new facility and file notice thereof with the Commission).

Furthermore, if the Commission grants a CPCN for new gas-fired capacity in excess of the 376 MW of coal capacity to be retired at the Asheville site, it should require DEP to retire additional coal capacity in an amount corresponding to the incremental gas-fired capacity authorized by the CPCN. The Commission has previously recognized that such a condition was appropriate in similar circumstances: in the Wayne County Order discussed above, operating under a similar legislative mandate requiring an expedited decision on a CPCN, the Commission concluded that "the expedited procedures [in the statute] should be used to certificate new capacity reasonably proportionate to the capacity retired." Wayne County Order at 8. Accordingly, the Commission ordered the utility to submit within 60 days "a plan to retire additional unscrubbed coal-fired generating capacity reasonably proportionate to the amount of incremental generating capacity authorized by the certificate above 400 MW," the approximate capacity being retired at the site. Wayne County Order at 11. A similar condition would be necessary in this proceeding as well, to "help curb overexpansion of generating facilities beyond the needs of the service area." *High Rock Lake Ass'n.*, 37 N.C. App. at 140, 245 S.E.2d at 790.

2. <u>The Commission Should Hold DEP to Its Commitments Regarding Clean Energy Resources.</u>

DEP acknowledges that the energy landscape is changing rapidly due to the emergence of new technologies. Application at 13. In its Application, DEP states that the Company "will work aggressively to transition to a cleaner and smarter energy future though active community engagement, deliberate investment in distributed energy resources ("DER") and greater promotion of and access to [demand-side management and energy efficiency] programs in the DEP-Western Region which may delay or eliminate the need for the contingent Asheville CT unit." *Id.* at 11. DEP states that it will engage with stakeholders on efforts such as an emerging collaborative effort to maximize participation and effectiveness of existing demand-side management and energy efficiency ("DSM/EE") programs. *Id.* at 12.

This collaborative effort, building on the Community Clean Energy Policy Framework[3] developed with community leaders and stakeholders in the Asheville region, is welcome and holds promise in increasing energy savings from EE and peak demand reduction from DR programs—particularly at times of peak demand—in DEP-W. The Commission has previously recognized the potential value of peak demand reduction strategies that could be implemented by DEP. *See, e.g.*, *Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice*, Docket No. E-2, Sub 1070 (November 16, 2015) at 17 (requiring discussion of customer notifications of forecasted peak demand conditions by DEP's Carolinas Energy Efficiency Collaborative).

[3] Community Clean Energy Policy Framework, *available at* http://www.ashevillenc.gov/Portals/0/city-documents/sustainability/sacee/COMMUNITY%20CLEAN%20ENERGY%20POLICY%20FRAMEWORK%20w%20Addendum%20-%202015-07-30.pdf .

DEP also states in its Application that it will pursue renewable energy technologies and energy storage to address energy use and demand in DEP-W. DEP plans to develop 15 MW of new utility-scale, community or rooftop solar generation, or a combination thereof, in DEP-W over the next seven years. Application at 12-13. Although DEP-W is a winter-peaking part of DEP's system, with peak demand occurring in the early morning, solar would also contribute to customer needs during non-peak times of higher demand, such as hot summer afternoons.

DEP also states in its Application that the Company is "committed to investing in a minimum of 5 MW utility-scale storage pilot in the DEP-Western Region within the next 7 years consistent with the goal of delaying or eliminating the need for the contingent Asheville CT unit in 2023." Application at 13. The cost of energy storage is plummeting, and rapidly evolving energy storage technology has the potential to provide a suite of benefits to customers in DEP-W—by bolstering reliability, relieving congestion on the transmission and distribution grid, providing backup power and helping customers on time-of-use rates to manage their bills.[4]

The Commission should expressly require DEP to honor these commitments to clean energy resources in DEP-W. With regard to the emerging collaborative effort to develop DSM/EE resources in DEP-W, the Commission should hold DEP to the intention expressed in its Application and establish a timeline with clear goals and reporting requirements for the collaborative. The Commission should also require DEP to meet its commitments regarding solar energy and energy storage in DEP-W, and require the Company to file annual updates on its continuous evaluation of these resources. Given

[4] Attachment 3, Rocky Mountain Institute, The Economics of Battery Energy Storage (Executive Summary) (September 2015), Figure ES1.

that most of the solar development in North Carolina is utility-scale, this evaluation should emphasize the potential for distributed solar. Such conditions would effectuate our State's policies of promoting demand-side and renewable resources and help customers in DEP's Western Region realize the benefits of these clean energy sources.

## RELIEF REQUESTED

MountainTrue and the Sierra Club respectfully request that the Commission grant the following relief with respect to DEP's Application:

1. Deny DEP's request for a certificate of public convenience and necessity for the Project without prejudice until DEP has submitted an amended application that addresses the flaws discussed herein and meets the public convenience and necessity standard as determined by the Commission. The Commission should require DEP to conduct the following analyses and include them in any such amended application:
    a. Establish the basis for DEP's claim of import constraints to DEP-W, and provide the underlying analyses that support that claimed level of import capability;
    b. Re-examine its methodology for determining the amount of local generation required to meet NERC reliability standards;
    c. Re-examine hourly load data in DEP-W to determine whether simple cycle combustion turbine units, rather than combined cycle units, would better meet customer needs in 2020;
    d. Complete the resource adequacy study initiated by Astrape Consulting and review the basis for the change from a 17% reserve margin to a 14.5% reserve margin;
    e. Analyze the creation of a single BA for DEP-W, DEP-E, and DEC, and a reserve sharing arrangement among these three entities;
    f. Analyze the potential for EE, DSM, and other demand-reduction and energy-saving strategies to reduce the need for fossil fuel generation in the DEP-W region; and
    g. Analyze whether to retrofit or retire the remaining coal units on the DEP and DEC systems.

2. In the alternative, without waiving our arguments to the contrary, if the Commission does grant a certificate of public convenience and necessity to DEP for new gas-fired generation at the Asheville site pursuant to the pending Application, it should only issue a CPCN for two 185 MW units; should deny the Application with respect to the third, contingent CT unit; and should impose the following conditions:

a. The conditions listed under No. 1, above;
b. Require that no later than January 31, 2020, DEP shall permanently cease operation of the two coal-fired generating units at its Asheville facility and shall file with the Commission in this docket a notice that operation of the units has been terminated;
c. Direct DEP to seek the necessary approvals for the 15 MW of solar and 5 MW of storage referred to in the Application on a fixed schedule established by the Commission, and to file annual reports regarding its continuous evaluation of these resources; and
d. Require DEP to embark on a collaborative planning effort with stakeholders in the DEP-W region to analyze whether additional demand response, energy efficiency, distributed generation, or renewable energy projects should be included in DEP's resource portfolio, with a concentrated effort to locate these resources in DEP-W. The Commission should establish a MW/MWh reduction goal and specific reporting requirements for this process.

3. Finally, and again in the alternative, without waiving our arguments to the contrary, if the Commission does grant a certificate of public convenience and necessity to DEP for the Project as proposed in the Application, it should impose the following conditions:
    a. The conditions listed under Nos. 1 and 2, above; and
    b. Retirement of additional coal-fired generating capacity equal to the amount of incremental generating capacity authorized by the certificate above 379 MW.

Respectfully submitted this 12th day of February, 2016.

s/Gudrun Thompson
Gudrun Thompson
N.C. Bar No. 28829
Southern Environmental Law Center
601 W. Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

Austin D. Gerken, Jr.
N.C. Bar No. 32689
Southern Environmental Law Center
22 S. Pack Square, Suite 700
Asheville, North Carolina 28801

*Attorneys for MountainTrue and the Sierra Club*

# VERIFICATION

I, Gudrun Thompson, verify that the contents of the foregoing Comments of MountainTrue and the Sierra Club are true to the best of my knowledge, except as to those matters stated on information and belief, and as to those matters, I believe them to be true. I am authorized to sign this verification on behalf of the MountainTrue and the Sierra Club.

Gudrun Thompson

Date: February 12, 2016

Orange County, North Carolina

Sworn to and subscribed before me this day by Gudrun Thompson

This 12th day of February, 2016

LOU ANN PHELPS
Notary Public, North Carolina
Durham County
My Commission Expires
October 25, 2016

Signature

Lou Ann Phelps, Notary Public

My commission expires: Oct. 25, 2016

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Comments of MountainTrue and the Sierra Club as filed today in Docket No. E-2, Sub 1089 has been served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 12th day of February, 2016.

s/ Robin G. Dunn

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-2, SUB 1089**

| | | |
|---|---|---|
| In the Matter of | ) | |
| Application of Duke Energy Progress, LLC, for | ) | |
| a Certificate of Public Convenience and Necessity | ) | AFFIDAVIT |
| To Construct a 752-MW Natural Gas-Fueled | ) | OF |
| Electric Generation Facility in Buncombe | ) | RICHARD S. HAHN |
| County Near the City of Asheville | ) | |
| | ) | |

I, Richard S. Hahn, first being duly sworn, do depose and say:

I am a principal consultant with Daymark Energy Advisors, Inc. ("Daymark"), a Boston-based energy consulting firm formerly known as La Capra Associates. Daymark offers a suite of advisory and technical services to deliver comprehensive and integrated solutions to our clients' decision challenges in the complex energy marketplace. Our services address all facets of the energy industry: technologies, systems, markets, regulations, planning models and methods, policy, transactions and communications with stakeholders. Our objective is to provide each client targeted advice and analysis needed to make effective decisions, assuring that our services are comprehensive and our solutions consider the full dimension of the problem. I have been employed by Daymark since 2004. Prior to joining Daymark, I was employed by NSTAR Electric & Gas ("NSTAR").

I have diverse experience in both regulated and unregulated companies. Since joining Daymark in 2004, I have advised clients on matters regarding energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, transmission projects and non-transmission alternatives, reliability assessments, power procurement and contracts, mergers and acquisitions, retail and wholesale electric rates and tariffs, utility operations, transactional audits, litigation, and renewable energy projects. Prior to joining La Capra Associates, I was a senior executive with NSTAR (now Eversource Energy), where my diverse responsibilities included resource planning, electricity markets, utility operations, rates, sales and marketing, engineering, business development, management of unregulated energy subsidiaries, and R&D. I have an M.B.A. from Boston College and an M.S. in Electrical Engineering from Northeastern University with an emphasis in powering engineering. I am a registered Professional Engineer in the Commonwealth of Massachusetts. I have testified on numerous occasions before many state regulatory commissions, and also before the Federal Energy Regulatory Commission. My full resume is provided in Exhibit E attached to this affidavit.

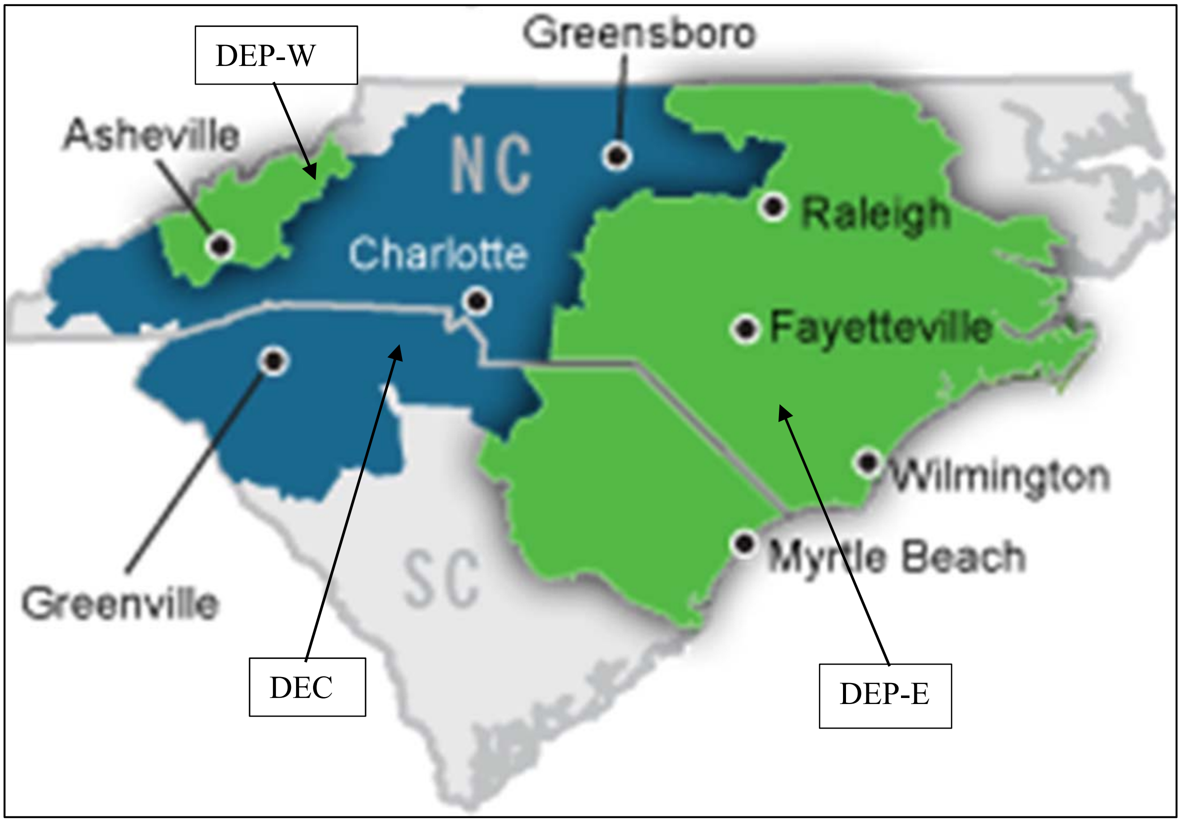
I was retained by the Southern Environmental Law Center ("SELC"), on behalf of SELC's clients MountainTrue and the Sierra Club, to review the Application of Duke Energy Progress, LLC ("DEP") to construct the Western Carolinas Modernization Project ("WCMP" or the "Project"), which was filed on January 15, 2016. The Commission has afforded interested parties until February 12, 2016 to file written comments.

The purpose of my affidavit is to present the results of my review. I reviewed the DEP Application and Exhibits 1A, 1B, 3, and 4. I also reviewed various publicly available documents and information regarding the Project and the DEP system, and certain documents provided by SELC. In addition, I received responses to certain data requests submitted to DEP by SELC.

## THE DEP SYSTEM

DEP's service territory is divided into two geographic areas that are separated by Duke Energy Carolinas ("DEC"). Figure 1, below, provides a high level map showing these areas. The Project would be located in DEP-W, the portion of the DEP system in western North Carolina near the border with Tennessee. The January 15, 2016 Application states that DEP-W is a Balancing Authority Area ("BAA"). The National Electric Reliability Corporation ("NERC") defines a BAA as the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority ("BA"). The BA is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BAA, and supports interconnection frequency in real time. The BA maintains load-resource balance within this area. DEP-E and DEC are also BAAs.

**Figure 1**
**DEC and DEP Service Territories**[1]




DEP-W has six transmission lines that connect it to neighboring systems. These are referred to as tie-lines. Table 1 below provides a summary of those tie-lines. The sum of the individual capacity ratings of these six lines is more than 2,200 megavolt amperes ("MVA").

**Table 1: DEP-W Tie-lines to Neighboring Systems**

| | Line Voltage | | | | |
|---|---|---|---|---|---|
| **Area** | **230KV** | **138KV** | **161KV** | **115KV** | **Total** |
| PJM | 1 | 1 | | | 2 |
| DEC | 2 | | | 1 | 3 |
| TVA | | | 1 | | 1 |
| Total | 3 | 1 | 1 | 1 | 6 |

[1] Source: https://www.duke-energy.com/accounts.

## THE PROJECT

In its current form, the Project consists of retiring the existing two coal-fired Asheville generating units in DEP-W with a combined capacity of 379 MW, and constructing two new 280 MW natural gas-fueled combined cycle ("NGCC") electric generating units, with a target in-service date of the fall of 2019, with a combined capacity of 560 MW. The Project also includes a 186 MW natural gas-fueled simple cycle combustion turbine ("CT") unit, with a possible in-service date of 2023. The application states that the 2023 simple cycle combustion turbine unit may be avoided or delayed due to the utilization of other technologies and programs to meet the future peak demand requirements in the region; related onsite transmission facilities; and future new solar generation at the Asheville plant site. DEP's application states that it is currently in the early stages of formalizing a partnership to explore ways to maximize deployment and effectiveness of programs and innovative energy solutions to reduce energy use in the DEP-W. DEP also has two existing 185 MW combustion turbine units at the Asheville plant site that will continue operation.

## ISSUES AND CONCERNS

In the brief time that has been afforded for my review of this application, I have identified a number of concerns and issues regarding the conclusion to build 746 MW of new capacity to replace 379 MW of existing generating capacity. In the remainder of this section of my affidavit, I discuss these issues and concerns.

A. <u>DEP's claim of import constraints lacks support in the record.</u>

The need for new capacity to replace the two existing Asheville coal plants is based primarily upon a claimed need to maintain local reliability. DEP asserts that DEP-

W is an import-constrained area, and that because the import capability is insufficient to meet local peak loads, the presence of a certain amount of local generation is required. According to the Statement of Need attached as Exhibit 1B to DEP's application, the Total Transmission Import Capability for the DEP-W area is 750 MW. The legitimacy of the DEP-W import constraints is an important issue. DEP has not provided the underlying analyses that support that claimed level of import capability, which is substantially lower than the aggregate capability of the tie-lines of 2,200 MVA from DEP-W to neighboring regions. Until the basis for the 750 MW import value is reviewed in detail, it is impossible to determine whether DEP has a need for local generation in DEP-W, and if so, how much local generation is required. I also note that DEP states that DEP-W is a separate BA, but DEP files a single Annual Balancing Authority Report Form 714 with FERC with DEP-W and DEP-E as a single BA. The basis for this combined filing is unsupported and should be explored further.

B. <u>DEP's methodology for determining the amount of local generation needed may be stricter than reliability standards require.</u>

Even if DEP's claimed import capability is assumed to be correct, DEP's methodology for determining the amount of local generation required is also unsupported and should also be reviewed in detail. DEP's methodology, which is provided in Table 1 of DEP's Exhibit 1B, may be summarized as follows:

1. Calculate the amount of Local Generating Capacity in DEP-W by summing the capability of each generating unit in DEP-W.
2. Calculate the amount of Usable Transmission Capacity by subtracting the capacity of the largest generating unit in DEP-W from the Total Transmission Import Capability.

3. Add the Local Generating Capacity to the Usable Transmission Capacity.
4. From this sum, deduct the peak load to arrive at Total Reserves.
5. From Total Reserves, deduct the capacity of the second largest generating unit in DEP-W.
6. The resulting difference must be positive if DEP-W is to be reliable.

Exhibit A, attached to this affidavit, provides a detailed summary of DEP's calculations from 2020 to 2030, which produces the same results as DEP's Exhibit 1B: Statement of Need. DEP's calculations remove the two largest units in DEP-W from the capacity that can be relied upon. As shown in Exhibit A, DEP assumes that the two existing Asheville coal plants are retired by 2020, two new 280 MW NGCC generating units are added in 2020, and a new 186 MW CT unit is added in 2024. Utilities often plan for unexpected events, such as generator or transmission line outages, that may occur. Such events are referred to as contingencies. DEP's methodology assumes that two contingencies or generator outages occur after transmission imports are already restricted. Because the two new 280 MW NGCC generating units become the two largest units in DEP-W, DEP excludes them from the area capacity that can be relied upon. DEP claims that this methodology complies with NERC reliability standards, but based upon the information in the Application, I do not agree. The removal of the two largest generating units as contingencies appears to apply a standard that is stricter than NERC requires. This methodology needs to be examined fully, along with the Total Transmission Import Capability, before one can conclude that DEP has a need for the Project.

C. DEP's proposal is oversized relative to the need.

Even if DEP's methodology for determining local generation need and its assumed transmission import capability are accepted, the choice of the size of the proposed Project must be re-visited. It does not make sense to construct two new 280 MW NGCC generating units, and then have these units essentially become the contingencies that are eliminated to determine net available capacity. New units of a smaller capacity will produce the same level of reliability.

If the two existing Asheville coal plants are assumed to be retired by 2020 and not replaced, the two largest remaining existing generating units in DEP-W are the two existing 185 MW CTs at Asheville station. Exhibit B attached to this affidavit shows the impact on local reliability of (a) reducing the size of the two proposed new 280 MW NGCC units in 2020 to two new 185 MW NGCC units and (b) reducing the proposed 186 MW new CT unit in 2024 to 100 MW.

Under these re-sized assumptions, the level of local reliability is virtually the same as under the proposed Project. This result makes sense. The two existing Asheville coal units have a combined capacity of about 379 MW. Therefore, replacing the two existing coal units with two new 185 MW units, or 370 MW total, should maintain local reliability. Thus, even if I accept DEP's reliability methodology and its assumptions, the size of the proposed Project is simply too big. Reducing the size of the Project as I propose would reduce the total costs to be charged to DEP's customers. The reduction in size will also reduce total emissions in the area. Therefore, at a minimum, the Project should be reduced to two new 185 MW units in 2020, and one new contingent 100 MW unit in 2024.

D. <u>DEP's proposed generating unit type is not properly matched to the hours of need.</u>

My next concern is with the type of new generation being proposed in DEP-W. DEP has proposed to add two 280 MW combined cycle units in 2020. However, the new capacity is not needed in all hours of the year. In the year 2020, I estimate that the existing local generation and transmission import capability in DEP-W can support 860 MW of load. Exhibit C attached to this affidavit provides the detail of how this threshold load level was determined. In preparing Exhibit C, I used DEP's own reliability methodology and assumptions. Thus, any time area loads in DEP-W are at or below 860 MW, no new generating capacity is needed in DEP-W even if the existing Asheville coal plants are retired and not replaced.

Next, I examined hourly loads to determine how often load exceeds the 860 MW of existing capacity. Based on hourly load data for DEP, I estimate that hourly loads for the DEP-W area are above 860 MW for only 625 hours per year.[2] Such high loads would only occur on hot summer days or cold winter days. Exhibit D attached to this affidavit provides a graphical representation of this data. Even if the coal units retire and are not replaced, the existing capacity will be adequate except during times of unusually high demand, during which times peaking generation can meet the need. This suggests that simple cycle combustion turbine units, rather than the combined cycle units proposed by DEP, should have been considered to replace the coal units in the 2020 timeframe. Using simple cycle CTs will further reduce costs and local emissions, as these units will run

[2] Hourly loads for the DEP system were obtained from DEP's 2014 FERC Form 714 Report. This load shape was applied to the DEP-W peak load to arrive at estimated hourly loads for DEP-W. Actual hourly loads for DEP-W were not available. According to DEP's 2014 FERC Form 714 Report, the DEP system peak load in 2014 of 14,215 MW occurred in January, a winter month. Therefore using DEP system-wide hourly load data is a reasonable proxy for DEP-W hourly loads.

fewer hours during the year. It would be possible for DEP to initially build simple cycle combustion turbine units with the possibility of conversion to combined cycle operation at a later date, when and if additional intermediate to baseload capacity is needed in DEP-W. This option does not appear to have been considered by DEP.

E. DEP has not justified its system-wide planning reserve margin.

DEP has also asserted that the Project will contribute towards meeting DEP's system-wide needs.[3] DEP bases its system-wide resource adequacy need on a reserve margin of 17%. This reserve level is a large increase from the previous year's value of 14.5%. This increase in reserve margin increases the amount of capacity DEP needs. DEP's 2014 peak load was 14,215 MW. By applying a 17.0% reserve margin instead of 14.5% increases DEP capacity requirements by 355 MW, which is only slightly less than the capacity of the Asheville coal plants that will be retired. As explained in DEP's 2015 Integrated Resource Plan Update Report, attached to the application as Exhibit 1A, the updated 17% reserve margin is based on the "initial results" of a resource adequacy study that Astrape Consulting undertook in 2015. Exhibit 1A at 12. This study should be completed and the issue needs to be analyzed in detail before the higher reserve margin is used in any resource needs assessment. It is premature to propose any resource additions to meet the reserve before that study and revised needs assessment is completed.

When Duke Energy merged with Progress Energy to place DEP and DEC under the same parent company, a Joint Dispatch Agreement ("JDA") for DEP and DEC was established as a means of creating merger savings. However, DEP has stated in responses to data requests from SELC that DEP and DEC individually plan to meet a 17% reserve margin. With the merger and the JDA, I see no reason why DEP-W, DEP-

[3] See PDF page 5 of 15 in Exhibit 1B: Statement of Need.

E, and DEC BAs should not be combined into one BA and have these three entities implement a Reserve Sharing Agreement to complement the JDA. A Reserve Sharing Agreement will almost certainly reduce the system-wide reserve margin and should not exacerbate the DEP-W import limitations. A Reserve Sharing Agreement should be studied regardless of whether the Project is approved or not.

F. DEP has not adequately analyzed alternatives that could eliminate or reduce the need for the Project.

Given the accelerated schedule in this proceeding, I have not reviewed the potential for solar and energy efficiency to defer or avoid the need for new generation in DEP-W. Such alternatives may further reduce the size of the Project, however, and should be analyzed in detail. Based on my review of the DEP's application, it does not appear that DEP has conducted a thorough review of such alternatives.

DEP also does not appear to have examined some purchased power alternatives to the Project. For example, the four Smoky Mountain Hydro units near the North Carolina-Tennessee border, have a capacity of 378 MW and produce 1.4 million MWh annually. These units are in the TVA system, which is connected to DEP-W by a single 161 KV line from TVA to the substation at the Walters Hydro Plant in DEP-W. It is my understanding that the power produced by these units is not currently contracted for purchase. This option may be a full or partial alternative to the Project, but DEP does not appear to have studied it. Even if the transmission tie-line to TVA needed to be upgraded to accommodate a purchase from Smoky Mountain Hydro, this option should at least be evaluated. I also note that Columbia Energy Center has intervened in this proceeding with an offer to sell its output to DEP. This option should also be explored and analyzed before a commitment to build new capacity.

## CONCLUSION

I have identified a number of issues and concerns with DEP's application to build the WCMP. The underlying needs assessment has not been fully analyzed or demonstrated, and there are feasible alternatives that DEP has not considered.

At a minimum, the proposed Project should be downsized. It is simply too large. Using DEP's own reliability model and assumptions, reliability in DEP-W can be maintained with two 185 MW units in 2020 in place of the proposed two 280 MW units in 2020. The contingent 186 MW unit tentatively scheduled for 2024 should at least be downsized to 100 MW. This contingent unit should not be approved at this time. It takes two to four years to permit and construct new generating capacity, depending upon capacity type. For example, DEP has proposed in January 2016 to permit and construct new generation by the fall of 2019, or less than four years. Thus, DEP has ample time to apply for a CPCN for a new generating unit in 2024 if it later demonstrates a need for new capacity in that timeframe.

Further, DEP should analyze the creation of a single BA for DEP-W, DEP-E, and DEC, and a reserve sharing arrangement among these three entities. This action has the potential to save ratepayers money and accordingly, this analysis should be undertaken regardless of whether a CPCN is approved at this time.

DEP's request for a Certificate of Public Convenience and Necessity ("CPCN") for the Project, as proposed, should not be granted until the Company has addressed these issues and concerns.

This completes my affidavit.

Richard A Hahn

Richard S. Hahn

Sworn to and subscribed before me

this the 11 day of February, 2016.

Pamela J Hadley

Pamela J Hadley

Notary Public

My Commission Expires March 1, 2016

PAMELA J HADLEY
MY COMMISSION #EE174996
EXPIRES: MAR 01, 2016
Bonded through 1st State Insurance

NOTARY PUBLIC STATE OF FLORIDA

## Exhibit A

### DEP-W LOAD & CAPACITY TABLE - MW

per Application Statement of Need

| line # | Item | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Generating Capacity | | | | | | | | | | | | |
| 2 | existing Asheville 3 CT | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | |
| 3 | existing Asheville 4 CT | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | |
| 4 | existing Walters 1 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | |
| 5 | existing Walters 2 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | |
| 6 | existing Walters 3 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | |
| 7 | existing Marshal 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | |
| 8 | existing Marshal 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | |
| 9 | new 1x1 CC unit 1 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | |
| 10 | new 1x1 CC unit 2 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | |
| 11 | new CT in 2024 | 0 | 0 | 0 | 0 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | |
| 12 | Subtotal | 1,046 | 1,046 | 1,046 | 1,046 | 1,231 | 1,231 | 1,231 | 1,231 | 1,231 | 1,231 | 1,231 | |
| 13 | | | | | | | | | | | | | |
| 14 | Transmission Import Capability | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | |
| 15 | Transmission Reliability Margin (TRM) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | largest unit in DEP-W |
| 16 | Usable transmission | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | |
| 17 | | | | | | | | | | | | | |
| 18 | Total Usable Capacity | 1,516 | 1,516 | 1,516 | 1,516 | 1,701 | 1,701 | 1,701 | 1,701 | 1,701 | 1,701 | 1,701 | |
| 19 | Peak Load | 1,146 | 1,170 | 1,187 | 1,199 | 1,214 | 1,243 | 1,259 | 1,278 | 1,297 | 1,310 | 1,333 | |
| 20 | Total Usable Capacity less Peak Load | 370 | 346 | 329 | 317 | 487 | 458 | 442 | 423 | 404 | 391 | 368 | |
| 21 | | | | | | | | | | | | | |
| 22 | Contingency | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | (280) | 2nd largest unit in DEP-W |
| 23 | Net | 90 | 66 | 49 | 37 | 207 | 178 | 162 | 143 | 124 | 111 | 88 | |

## Exhibit B

### DEP-W LOAD & CAPACITY TABLE - MW

With Revised Project Size

| line # | Item | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Generating Capacity | | | | | | | | | | | | |
| 2 | existing Asheville 3 CT | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | |
| 3 | existing Asheville 4 CT | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | |
| 4 | existing Walters 1 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | |
| 5 | existing Walters 2 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | |
| 6 | existing Walters 3 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | |
| 7 | existing Marshal 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | |
| 8 | existing Marshal 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | |
| 9 | new 1x1 CC unit 1 | **185** | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | reduced from 280 MW |
| 10 | new 1x1 CC unit 2 | **185** | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | reduced from 280 MW |
| 11 | new CT in 2024 | 0 | 0 | 0 | 0 | **100** | 100 | 100 | 100 | 100 | 100 | 100 | reduced from 186 MW |
| 12 | Subtotal | 856 | 856 | 856 | 856 | 956 | 956 | 956 | 956 | 956 | 956 | 956 | |
| 13 | | | | | | | | | | | | | |
| 14 | Transmission Import Capability | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | |
| 15 | Transmission Reliability Margin (TRM) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | largest unit in DEP-W |
| 16 | Usable transmission | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | |
| 17 | | | | | | | | | | | | | |
| 18 | Total Usable Capacity | 1,421 | 1,421 | 1,421 | 1,421 | 1,521 | 1,521 | 1,521 | 1,521 | 1,521 | 1,521 | 1,521 | |
| 19 | Peak Load | 1,146 | 1,170 | 1,187 | 1,199 | 1,214 | 1,243 | 1,259 | 1,278 | 1,297 | 1,310 | 1,333 | |
| 20 | Total Usable Capacity less Peak Load | 275 | 251 | 234 | 222 | 307 | 278 | 262 | 243 | 224 | 211 | 188 | |
| 21 | | | | | | | | | | | | | |
| 22 | Contingency | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | (185) | 2nd largest unit in DEP-W |
| 23 | Net | 90 | 66 | 49 | 37 | 122 | 93 | 77 | 58 | 39 | 26 | 3 | |

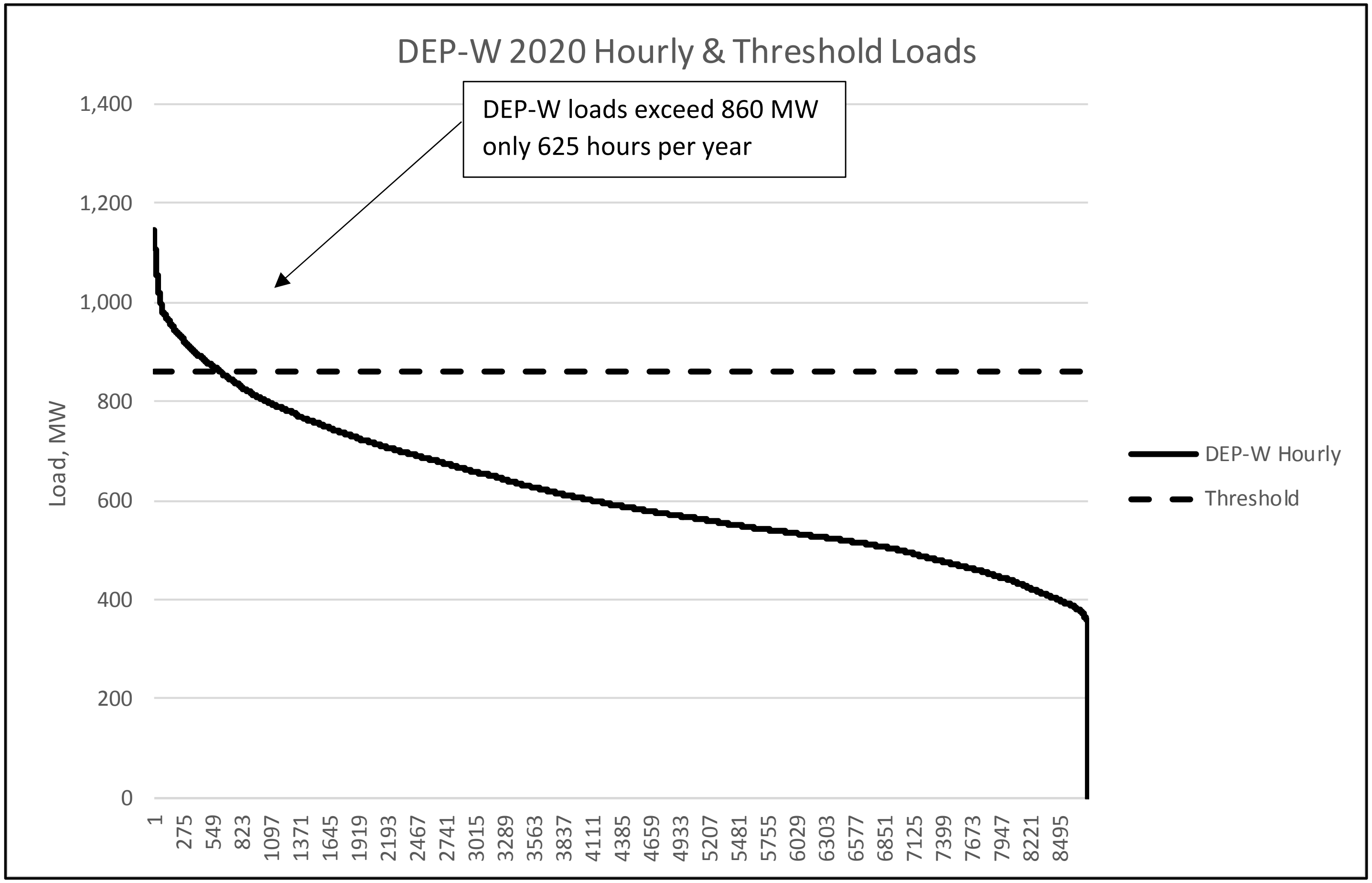
## Exhibit C

### DEP-W LOAD & CAPACITY TABLE - MW

Load That Can Be Supported By The Existing System

| line # | Item | | 2020 | |
|---|---|---|---|---|
| 1 | Generating Capacity | | | |
| 2 | | existing Asheville 3 CT | 185 | |
| 3 | | existing Asheville 4 CT | 185 | |
| 4 | | existing Walters 1 | 36 | |
| 5 | | existing Walters 2 | 40 | |
| 6 | | existing Walters 3 | 36 | |
| 7 | | existing Marshal 1 | 2 | |
| 8 | | existing Marshal 2 | 2 | |
| 9 | | new 1x1 CC unit 1 | 0 | |
| 10 | | new 1x1 CC unit 2 | 0 | |
| 11 | | new CT in 2024 | 0 | |
| 12 | | Subtotal | 486 | |
| 13 | | | | |
| 14 | Transmission Import Capability | | 750 | |
| 15 | Transmission Reliability Margin (TRM) | | (185) | largest unit in DEP-W |
| 16 | | Usable transmission | 565 | |
| 17 | | | | |
| 18 | Total Usable Capacity | | 1,051 | |
| 19 | Peak Load | | **860** | reduced from filed values |
| 20 | Total Usable Capacity less Peak Load | | 191 | |
| 21 | | | | |
| 22 | Contingency | | (185) | 2nd largest unit in DEP-W |
| 23 | Net | | 6 | |

**Exhibit D**



DEP-W 2020 Hourly & Threshold Loads
DEP-W loads exceed 860 MW only 625 hours per year
Load, MW
1,400
1,200
1,000
800
600
400
200
0
1
275
549
823
1097
1371
1645
1919
2193
2467
2741
3015
3289
3563
3837
4111
4385
4659
4933
5207
5481
5755
6029
6303
6577
6851
7125
7399
7673
7947
8221
8495
DEP-W Hourly
Threshold

**Exhibit E**
**Resume of Richard S. Hahn**

# Richard S. Hahn

Principal Consultant

## SUMMARY

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated companies. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, procurement of power supplies and portfolio management, transmission planning, rates, financial analysis, mergers and acquisitions, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn has testified on numerous occasions before state utility commissions, and has also testified before FERC.

## DETAILED CHRONOLOGY – DAYMARK ENERGY ADVISORS, INC.

- Daymark Energy Advisors was retained by the Wisconsin Citizens Utility Board to evaluate the application Wisconsin Power & Light for a Certificate of Public Convenience and Necessity to construct a 650 MW natural gas -fired combined cycle plant. We also reviewed a Purchased Power Agreement that was proposed as an alternative to the new plant.
- Reviewed a purchased power agreement between National Grid and Copenhagen Wind for the Rhode Island Division of Public Utilities and Carriers
- Performed an audit of Rocky Mountain Power Company's 2014 Energy Balancing Account, including a review of the Company's hedging program.
- Reviewed National Grid’s 2016 Standard Offer Supply (“SOS”) and Renewable Energy Standard (“RES”) Procurement Plans
- In 2014 and 2015, Daymark Energy Advisors was retained by the Wisconsin Citizens Utility Board (WI CUB) to evaluate the application American Transmission Company (“ATC”) for a Certificate of Public Convenience and Necessity (CPCN) to construct a 345 kV and a 230 KV transmission line from eastern Wisconsin to the Upper Peninsula of Michigan.
- Daymark Energy Advisors was retained by the Citizens Utility Board of Wisconsin (WI CUB) to evaluate the proposed merger between WEC and Integrys. Our assignment was to review the transaction and determine whether it complied with the Wisconsin merger standard, and if not, to develop implementable actions to ensure compliance.

- Maine Public Utilities Commission (“MPUC”) retained Daymark Energy Advisors to evaluate possible non-transmission alternatives (“NTAs”) to a proposed transmission substation and other ancillary transmission upgrades in the Lakes Region. This transmission project is proposed by Central Maine Power Company (“CMP”). CMP has filed for a Certificate of Public

Convenience and Necessity ("CPCN") for the proposed transmission enhancements and its filing states that this project is needed to resolve reliability concerns. Daymark Energy Advisors performed an independent reliability assessment and developed Alternative Resource Configurations ("ARCs") that could serve as NTAs and adequately address the reliability issues over the 2015 to 2030 planning horizon for this project. Daymark Energy Advisors also performed a life-cycle economic analysis of the ARCs versus the transmission project.

- Maine Public Utilities Commission ("MPUC") retained Daymark Energy Advisors to evaluate possible non-transmission alternatives ("NTAs") to a proposed transmission substation and other ancillary transmission upgrades in the Waterville-Winslow Region. This transmission project is proposed by Central Maine Power Company ("CMP"). CMP has filed for a Certificate of Public Convenience and Necessity ("CPCN") for the proposed transmission enhancements and its filing states that this project is needed to resolve reliability concerns. Daymark Energy Advisors performed an independent reliability assessment and developed Alternative Resource Configurations ("ARCs") that could serve as NTAs and adequately address the reliability issues over the 2015 to 2030 planning horizon for this project. Daymark Energy Advisors also performed a life-cycle economic analysis of the ARCs versus the transmission project.
- Reviewed and analyzed a proposed pilot program to implement a new street lighting program in Rhode Island that included metered, directly controlled LED street lights
- Reviewed and analyzed a risk assessment model prepared by Black and Veatch for Duke Energy Indiana, which was utilized to identify investments for the replacement of Transmission and Distribution ("T&D") infrastructure for its Transmission, Distribution, and Storage System Improvement Charges 7-year plan ("T &D Plan")
- Reviewed the Application of Rocky Mountain Power seeking approval from the Public Service Commission of Utah to increase electric rates. The scope of the assignment was to review the proposed additions to plant in-service
- Performed an audit of Rocky Mountain Power Company's 2013 Energy Balancing Account, including a review of the Company's hedging program.
- Performed an asset valuation to estimate the market value of all power plants owned by Public Service of New Hampshire. Presented results to the New Hampshire Public Utilities
- Reviewed a proposed Default Service Procurement Plan for PECO Energy for 2015-2017
- Reviewed a proposed Default Service Procurement Plan for PPL Electric Utilities for 2015-2017
- Reviewed a request by Wisconsin Public Service to increase retail rates.
- Reviewed and analyzed a proposed tariff and related documents for Rhode Island to acquire street lighting assets owned by NGRID. Presented findings to the Rhode Island Public utilities Commission.
- Analyzed a proposed interconnection of a 30mw off-shore wind project to the ISO New England grid. Presented findings to the Rhode Island Public Utilities Commission
- Reviewed NGRID's 2014 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors as well as NGRID's 2014 RES Charge and Reconciliation filing.

- Reviewed proposed TOU rates by PPL Electric on behalf of the Pennsylvania Office of Consumer Advocate
- Performed an analysis of a proposal to convert the Valley Power Plant in Milwaukee to switch from coal to natural gas; included a reliability assessment of the need for the plant to maintain local reliability
- Reviewed the adequacy of the supply of renewable energy certificates for 2015 and 2016 for impact on the Rhode Island Renewable Energy Standard
- Reviewed a purchased power agreement between National Grid and Champlain / Bowers Wind for the Rhode Island Division of Public Utilities and Carriers
- Daymark Energy Advisors was retained by the Nova Scotia Small Business Advocate to review and analyze the 2013 Annual Capital Expenditure ("ACE") Plan for Nova Scotia Power Incorporated ("the Company" or "NSPI"). I served as a key member of the team responsible for reviewed transmission projects.
- Served as an advisor to the Belmont Municipal Light Department in its efforts to upgrade its transmission interconnection to 115KV
- Performed an assessment of the proposed merger of Peoples Natural Gas and Equitable Gas Company for the Pennsylvania Office of Consumer Advocate.
- Reviewed the proposed default service procurement of UGI Utilities to procure standard offer service power supplies for its non-shopping customers for 2014 to 2017.
- Performed an audit of Rocky Mountain Power's 2012 Energy Balancing Account, including a review of the Company's hedging program.
- Reviewed a request by Wisconsin Public Service to implement the System Modernization and Reliability Project, a large-scale capital program to improve system reliability in Northern Wisconsin
- Served as a member of a Daymark Energy Advisors team advising the Arkansas Public Service Commission Staff regarding Entergy's Application to transfer ownership of transmission assets to ITC
- Reviewed and analyzed NGRID proposed 2013 LTCRER factor; provided written comments to RI PUC
- Reviewed Rocky Mountain Power Company's Energy Balancing Account filing for 2011; filed testimony before the Utah PSC
- Reviewed NGRID proposed tariff revisions for recovery of Long-Term Renewable Energy Contracts; provided written comments to RI PUC
- Analyzed proposed environmental upgrades to the Flint Creek coal unit in Arkansas; filed written testimony before the Arkansas PSC
- WI CUB WEPCO 2013 Rate Case; review prudence of capital and fuel costs; filed written testimony before the Wisconsin PSC
- Reviewed and analyzed a request for an Advanced Determination of Prudence for a new wind generation facility; filed written testimony before the North Dakota PSC

- Reviewed proposed 2013 -2015 Default Service Procurement Plan for PPL Utilities; filed written testimony before the Pennsylvania PUC.
- Analyzed forecast of projected capital additions to plant in service for forward-looking test year in Utah rate case. Filed testimony before the Utah Public Service Commission.
- Review and analysis of National Grid's proposed 2013 Standard Offer Service and Renewable Energy Standard procurement plan on behalf of the Rhode Island Division of Public utilities and Carriers.
- Review and analysis of National Grid's proposed long term renewable contracting plan on behalf of the Rhode Island Division of Public utilities and Carriers.
- Review and analysis of a long-term renewable energy contract between Black Bear Hydro and National Grid on behalf of the Rhode Island Division of Public Utilities and Carriers.
- Reviewed proposed 2013 -2015 Default Service Procurement Plan for PECO Energy on behalf of the Pennsylvania Office of Consumer Advocate
- Review National Grid's 2012 Electric Retail Rate Filing requesting Commission approval of various charges and adjustment factors for the Rhode Island Division of Public Utilities and Carriers
- Analyzed the request to the Wisconsin Public Service Commission for a CPCN for the Hampton - Rochester - La Crosse Baseline Reliability Project
- Performed an assessment of the TOU rates proposed by PPL Electric Utilities before the Pennsylvania Public Utilities Commission; Presented expert testimony providing the results of that assessment
- Reviewed the proposed merger between Exelon and Constellation Energy for its impact on market power; filed testimony before the Pennsylvania Public Utilities Commission
- Reviewed the proposed merger between Exelon and Constellation Energy for its impact on market power; filed testimony before the Federal Energy Regulatory Commission and the Maryland Public Service Commission
- Conducted an assessment of the request to the North Dakota Public Service Commission for an Advanced Determination of Prudence for the Montana Dakota Utilities GT; filed testimony before the North Dakota Public Service Commission
- Conducted an assessment of the request to the North Dakota Public Service Commission for an Advanced Determination of Prudence for the Big Stone Air Quality Control System; filed testimony before the North Dakota Public Service Commission
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Wisconsin Electric Power; filed testimony before the Public Service Commission of Wisconsin
- Analyzed proposed ceiling prices for Distributed Generation procurement for the Rhode Island Division of Public Utilities and Carriers in Docket 4288
- Reviewed proposed changes to National Grid's Distributed Generation Enrollment Process for the Rhode Island Division of Public Utilities and Carriers in Docket 4276

- Reviewed proposed changes to National Grid's interconnections standards for the Rhode Island Division of Public Utilities and Carriers in Docket 4277
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Northern States Power Wisconsin; filed testimony before the Public Service Commission of Wisconsin
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Madison Gas & Electric; filed testimony before the Public Service Commission of Wisconsin
- Analyzed proposed 2012 monitored and non-monitored fuel costs, market sales and revenues, capacity position, and performance parameters for Wisconsin Public Service; filed testimony before the Public Service Commission of Wisconsin
- Reviewed the proposed merger between Duke Energy and Progress Energy for compliance with merger approval standards and the impact of the merger on customers; filed testimony before the North Carolina Public Utilities Commission and the South Carolina Public Service Commission
- Analyzed the De-List Bid submitted by Vermont Yankee in ISO-NE capacity auctions. Filed statement at FERC presenting the results of that assessment.
- Performed an assessment of a proposal by Nova Scotia Power to increase spending on vegetation management activities as part of the 2012 rate case; filed testimony before the Nova Scotia Utility and Review Board
- Reviewed and analyzed a proposed Purchased Power Agreement between National Grid and Orbit Energy; filed testimony before the Rhode Island Public Utility Commission in Docket 4265
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Ascutney Vermont
- Reviewed and analyzed NGRID proposed SOS procurement plan and RES Compliance plan for 2012; provided testimony before the Rhode Island Public Utility Commission in Docket 4227
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Bennington Vermont
- Prepared follow-on analysis of Utah resource acquisition in rate case in Docket 10-035-124
- Reviewed and analyzed a proposed retail rate increase by Fitchburg Gas and Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Spending Plan, and an accompanying recovery mechanism
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Georgia, Vermont
- Reviewed and analyzed damages claimed in litigation between a developer of renewable energy facilities and the owner of the host site
- Evaluated the decision of PacifiCorp to acquire new generating resources in Utah. Filed testimony before the Public Service Commission of Utah

- Served as a principal advisor and key team member in Daymark Energy Advisors' assessment of strategic options for Entergy Arkansas, Inc. subsequent to its withdrawal from the Entergy System Agreement
- Reviewed the issues and documentation related to a complaint regarding the net metering issues for the Portsmouth Wind Turbine for the Rhode Island Divisions of Public Utilities and Carriers
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Jay, Vermont
- Reviewed and evaluated the construction and cost recovery of a large cogeneration plant for a mid-west utility; utilized heat balance analysis to develop new cost allocators between steam and electric sales.
- Analyzed fuel costs, market sales and revenues, capacity position, and performance parameters for a large- mid-west utility.
- Performed a review and analysis of the proposed merger between FirstEnergy and Allegheny Energy. Provided expert testimony before the FERC and the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Performed a study of non-transmission alternatives to a proposed transmission project in the Lewiston-Auburn area of Central Maine Power Company's service territory. Testified before the Maine Public Utilities Commission.
- Analyzed a proposed plan by National Grid to procure 2011 default service power supplies and comply with Renewable Energy Standards. Provided expert testimony before the Rhode Island Public Utilities Commission in Docket 4149.
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for PECO Energy
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for PPL Electric Utilities.
- Analyzed a purchase power agreement between National Grid and on offshore wind project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Reviewed and analyzed a proposed retail rate increase by Western Massachusetts Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Plan, and an accompanying recovery mechanism.
- Served as an advisor to the developer of a utility-scale Solar PV facility in Massachusetts.
- Evaluated a proposed Solar PV installation for a large retail customer in Massachusetts. Performed an analysis of the appropriate rate of return and its impact on facility electric costs and financial feasibility.
- Assessed the economic impact of an additional interconnection between ISO-NE and NYISO; analyzed impact on market prices and congestion.

- Reviewed and analyzed the capacity position of a large mid-west utility and the impact of that position on electric rates.
- Performed an economic evaluation of a proposed transmission line in New England. Assessed the project's ability to deliver renewable energy to load centers and the impact of the project on Locational Marginal Prices.
- Analyzed a proposed interconnection of a large new industrial load in Massachusetts. Evaluated proposed substation configuration and developed alternatives that achieved comparable reliability at lower costs. Assessed cost recovery options.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Pennsylvania Power & Light in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Philadelphia Electric Company in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Rhode Island Public Utilities Commission. Provided expert testimony before the Rhode Island Public Utilities Commission regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan
- Reviewed and analyzed Time-of-Use rates proposed by Pennsylvania Power & Light. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding compliance with Commission requirements, rate design, cost recovery, and consumer education issues.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan.
- Performed a review and analysis of the proposed merger between Exelon and NRG. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Reviewed the needs analysis and load forecast supporting a proposed Transmission Project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives. Developed and applied a probabilistic planning tool to model uncertainty in costs and operating parameters.

- Conducted a review of Massachusetts Electric Company's proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Conducted a review of Western Massachusetts Electric Company's proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Served as a key member of a Daymark Energy Advisors Team evaluating wind generation RFPs in Oklahoma.
- Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.
- Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.
- Analyzed proposed environmental upgrades to the Edgewater 5 coal-fired generating unit in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.
- Analyzed proposed environmental upgrades to the Columbia Energy Center coal-fired generating units in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.
- Analyzed proposed environmental upgrades to the Oak Creek coal-fired generating units in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony before the Public Service Commission of Wisconsin.
- Reviewed Pennsylvania Act 129 and Commission rules for Energy Efficiency Plans
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.
- Served as a key member of the Daymark Energy Advisors Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Vermont.
- Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.

- Served as an expert witness in litigation involving a contract dispute between the owner of a merchant power plant and the purchasers of the output of the plant.
- Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.
- Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.
- Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.
- Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.
- Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.
- Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.
- Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.
- Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.
- Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing power plants.
- Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.
- Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.
- Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.
- Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.
- Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.

- Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.
- Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.
- Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.
- Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.
- Assisted in the review of the impact of a major transmission upgrade in Northern New England.
- Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

## SELECTED EXPERIENCE – NSTAR ELECTRIC & GAS

**President & COO of NSTAR Unregulated Subsidiaries**

*Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.*

**Advanced Energy Systems, Inc.**

*Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.*

**NSTAR Steam Corporation**

*Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.*

**NSTAR Communications, Inc.**

*Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.*
*Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.*
*Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.*

*Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.*

**VP, Technology, Research, & Development, Boston Edison Company**

*Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.*

*Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.*

**VP of Marketing, Boston Edison Company**

*Promoted and sold residential and commercial energy-efficiency products and customer service programs.*

*Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.*

*Designed and marketed energy-efficiency programs.*

*Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.*

**Vice President, Energy Planning, Boston Edison Company**

*Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases*

*Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.*

*Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.*

*Negotiated and administered over 200 transmission and purchased power contracts.*

*Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.*

*Testified before federal and state regulatory agencies.*

## EMPLOYMENT HISTORY

**Daymark Energy Advisors, Inc**. (formerly La Capra Associates, Inc.) — Boston, MA
*Principal Consultant* — *2004 – present*

**Advanced Energy Systems, Inc**. — Boston, MA
*President and COO* — *2001-2003*

**NSTAR Steam Corporation** — Cambridge, MA
*President and COO* — *2001-2003*

**NSTAR Communications, Inc.**
*President and COO* — *1995-2003*

**Boston Edison Company** — Boston, MA

| | |
|---|---|
| *VP, Technology, Research, & Development* | *1993-1995* |
| *VP, Marketing, Boston Edison Company* | *1991-1993* |
| *Vice President, Energy Planning, Boston Edison Company* | *1987-1991* |
| *Manager, Supply & Demand Planning* | *1984-1987* |
| *Manager, Fuel Regulation & Performance* | *1982-1984* |
| *Assistant to Senior Vice President, Fossil Power Plants* | *1981-1982* |
| *Division Head, Information Resources* | *1978-1981* |
| *Senior Engineer, Information Resource Division* | *1977-1978* |
| *Assistant to VP, Steam Operations* | *1976-1977* |
| *Electrical Engineer, Research & Planning Department* | *1973-1976* |
| *Engineering co-op student* | *1970-1973* |

## EDUCATION

**Boston College** — Boston, MA
*Masters in Business Administration* — *1982*

**Northeastern University** — Boston, MA
*Masters in Science, Electrical Engineering* — *1974*

**Northeastern University** — Boston, MA
*Bachelors in Science, Electrical Engineering* — *1973*

## PROFESSIONAL AFFILLIATIONS

| | |
|---|---|
| **Director, La Capra Associates, Inc.** | 2005-2015 |
| **Elected Commissioner – Reading Municipal Light Board** | 2005-2012 |
| **Director, NSTAR Communications, Inc.** | 1997-2003 |
| **Director, Advanced Energy Systems, Inc.** | 2001-2003 |
| **Director, Neuco, Inc.** | 2001-2003 |
| **Director, United Telecom Council** | 1999-2003 |
| **Head, Business Development Division, United Telecom Council** | 2000-2003 |
| **Registered Professional Electrical Engineer in Massachusetts** | |

MountainTrue and Sierra Club First Data Request to Duke Energy Progress, LLC NCUC Docket No. E-2, Sub 1089—Western Carolinas Modernization Project November 9, 2015

2. Has DEP performed any studies in the past five (5) years to estimate the potential amount of technically feasible energy efficiency that could be implemented within its service territory? If so, please provide copies of such studies.

**RESPONSE:**

Please see the attached Market Potential Study performed by Forefront Economics in 2012.

PEC EE Potential
Assessment - Forefro

ATTACHMENT 3



ROCKY MOUNTAIN INSTITUTE

# THE ECONOMICS OF BATTERY ENERGY STORAGE

## HOW MULTI-USE, CUSTOMER-SITED BATTERIES DELIVER THE MOST SERVICES AND VALUE TO CUSTOMERS AND THE GRID

## EXECUTIVE SUMMARY

1820 FOLSOM STREET | BOULDER, CO 80302 | RMI.ORG


PUBLISHED OCTOBER 2015
DOWNLOAD AT: WWW.RMI.ORG/ELECTRICITY_BATTERY_VALUE

# AUTHORS

## AUTHORS

Garrett Fitzgerald, James Mandel, Jesse Morris, Hervé Touati

* Authors listed alphabetically. All authors from Rocky Mountain Institute unless otherwise noted.

## CONTACTS

James Mandel (jmandel@rmi.org)
Jesse Morris (jmorris@rmi.org)

## SUGGESTED CITATION

Fitzgerald, Garrett, James Mandel, Jesse Morris, and Hervé Touati. *The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid.* Rocky Mountain Institute, September 2015. <<http://www.rmi.org/electricity_battery_value>>

## ACKNOWLEDGMENTS

The authors thank the following individuals and organizations for offering their insights and perspectives on this work:

Jeff Cramer, 38 North Solutions
Paul De Martini, ICF International
Mark Dyson, Rocky Mountain Institute
Stacy M. Gasvoda, Gaelectric
Devi Glick, Rocky Mountain Institute
Leia Guccione, Rocky Mountain Institute
Lena Hansen, Rocky Mountain Institute
Ted Ko, Stem
Charles R. Shawley, Gaelectric
James Sherwood, Rocky Mountain Institute

Editorial Director: Peter Bronski
Editor: David Labrador
Art Director: Romy Purshouse
Images courtesy of Thinkstock unless otherwise noted.

## ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. In 2014, RMI merged with Carbon War Room (CWR), whose business-led market interventions advance a low-carbon economy. The combined organization has offices in Snowmass and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

# EXECUTIVE SUMMARY



UTILITIES, REGULATORS, and private industry have begun exploring how battery-based energy storage can provide value to the U.S. electricity grid at scale. However, exactly where energy storage is deployed on the electricity system can have an immense impact on the value created by the technology. With this report, we explore four key questions:

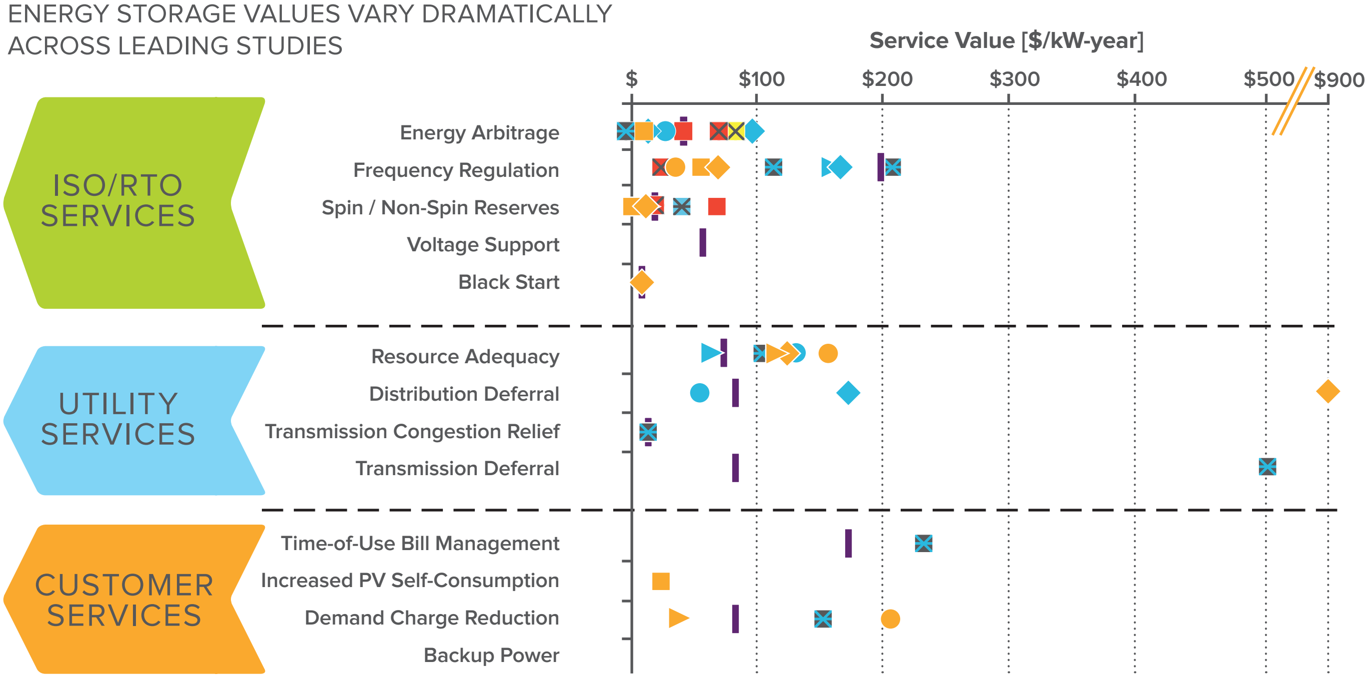
1. What services can batteries provide to the electricity grid?
2. Where on the grid can batteries deliver each service?
3. How much value can batteries generate when they are highly utilized and multiple services are stacked?
4. What barriers—especially regulatory—currently prevent single energy-storage systems or aggregated fleets of systems from providing multiple, stacked services to the electricity grid, and what are the implications for major stakeholder groups?

### *1. What services can batteries provide to the electricity grid?*

**Energy storage can provide thirteen fundamental electricity services for three major stakeholder groups when deployed at a customer's premises (behind the meter).**

To understand the services batteries can provide to the grid, we performed a meta-study of existing estimates of grid and customer values by reviewing six sources from across academia and industry. Our results illustrate that energy storage is capable of providing a suite of thirteen general services to the electricity system (see Figure ES1). These services and the value they create generally flow to one of three stakeholder groups: customers, utilities, or independent system operators/regional transmission organizations (ISO/RTOs).

FIGURE ES1
ENERGY STORAGE VALUES VARY DRAMATICALLY ACROSS LEADING STUDIES




*Results for both energy arbitrage and load following are shown as energy arbitrage. In the one study that considered both, from Sandia National Laboratory, both results are shown and labeled separately. Backup power was not valued in any of the reports.*

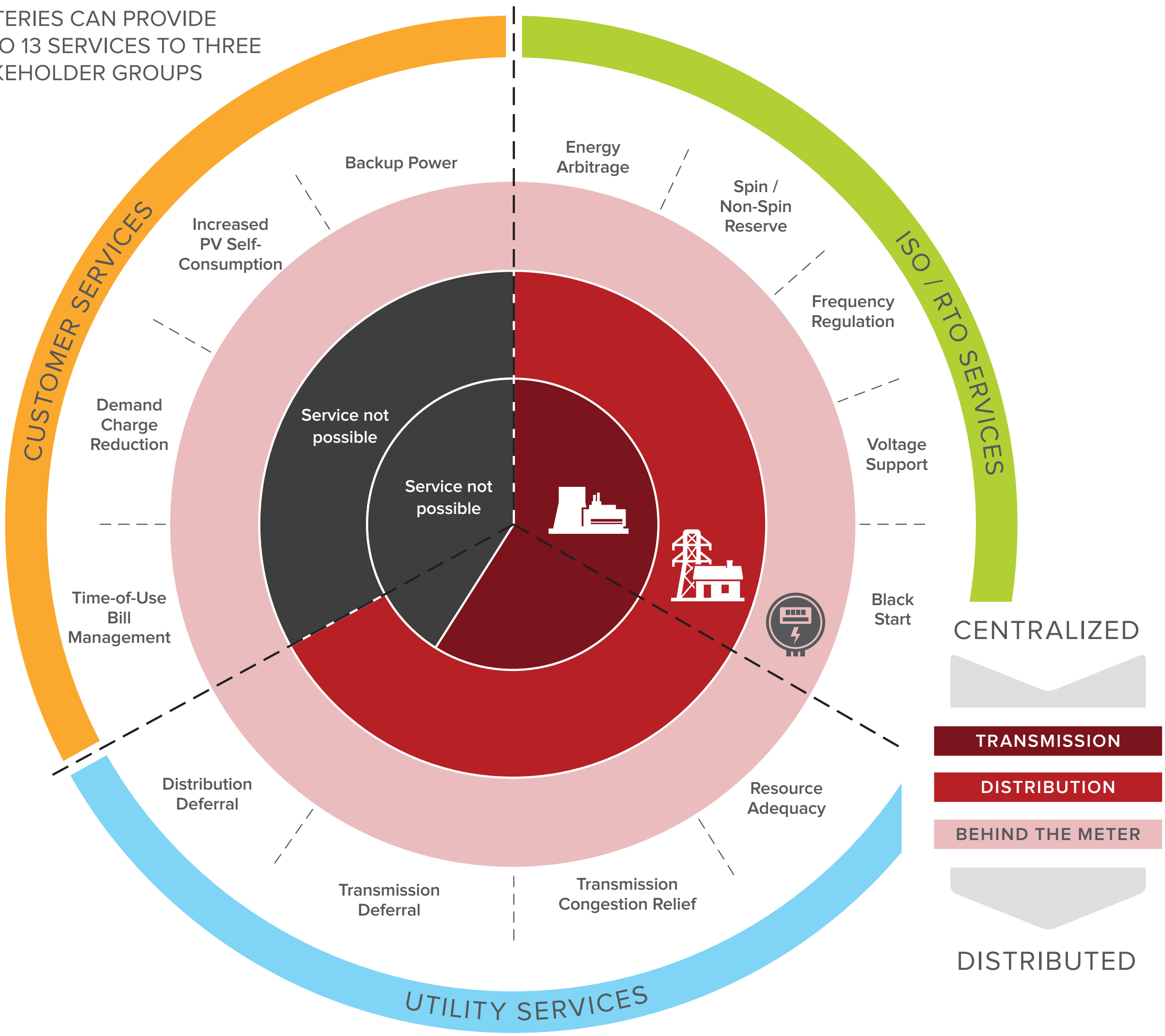
RMI UC I, RMI UC II, RMI UC III, RMI UC IV, NYSERDA, NREL, Oncore-Brattle, Kirby, EPRI Bulk, EPRI Short Duration, EPRI Substation, Sandia, Sandia: LF

### *2. Where on the grid can batteries deliver each service?*

**The further downstream battery-based energy storage systems are located on the electricity system, the more services they can offer to the system at large.**

Energy storage can be sited at three different levels: behind the meter, at the distribution level, or at the transmission level. Energy storage deployed at all levels on the electricity system can add value to the grid. However, customer-sited, behind-the-meter energy storage can technically provide the largest number of services to the electricity grid at large (see Figure ES2)—even if storage deployed behind the meter is not always the least-cost option. Furthermore, customer-sited storage is optimally located to provide perhaps the most important energy storage service of all: backup power. Accordingly, regulators, utilities, and developers should look as far downstream in the electricity system as possible when examining the economics of energy storage and analyze how those economics change depending on where energy storage is deployed on the grid.

**FIGURE ES2**
BATTERIES CAN PROVIDE UP TO 13 SERVICES TO THREE STAKEHOLDER GROUPS



### *3. How much value can batteries generate when they are highly utilized and multiple services are stacked?*

**Energy storage can generate much more value when multiple, stacked services are provided by the same device or fleet of devices...**

The prevailing behind-the-meter energy-storage business model creates value for customers and the grid, but leaves significant value on the table. Currently, most systems are deployed for one of three single applications: demand charge reduction, backup power, or increasing solar self-consumption. This results in batteries sitting unused or underutilized for well over half of the system's lifetime. For example, an energy storage system dispatched solely for demand charge reduction is utilized for only 5–50% of its useful life. Dispatching batteries for a primary application and then re-dispatching them to provide multiple, stacked services creates additional value for all electricity system stakeholders.

**... but the net value of behind-the-meter energy storage to the electricity system is difficult to generalize.**

A summary of grid values and services is not enough to answer a fundamental question: How does the value of energy storage shift when deployed at different levels on the electricity grid? Answering this question proves greatly complicated. The net value of providing each of thirteen services at different levels on the grid (transmission level, distribution level, or behind the meter) varies dramatically both across and within all electric power markets due to hundreds of variables and associated feedback loops. Hence, the values energy storage can provide vary dramatically from study to study, driven by grid-specific factors (see Figure ES1).

**Under prevailing cost structures, batteries deployed for only a single primary service generally do not provide a net economic benefit (i.e., the present value of lifetime revenue does not exceed the present value of lifetime costs), except in certain markets under certain use cases. However, given that the delivery of primary services only takes 1–50% of a battery's lifetime capacity, using the remainder of the capacity to deliver a stack of services to customers and the grid shifts the economics in favor of storage.**

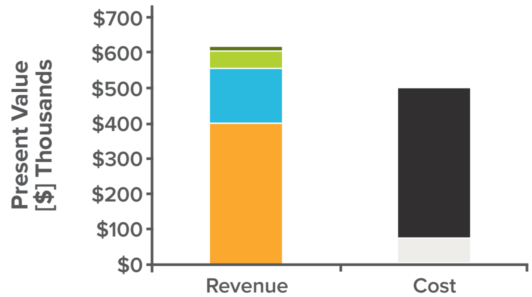
Using a simplified dispatch model, we illustrate the value of four behind-the-meter energy storage business cases and associated capital costs in the U.S. (conservatively, \$500/kWh and \$1,100–\$1,200/kW). Each case centers on delivery of a primary service to the grid or end user: storage is dispatched primarily to deliver this service and then secondarily provides several other stacked services based on the relative value of the service, battery availability, and other user-defined inputs to the model (see Figure ES3).

**Our results come with one major caveat: for any of the scenarios illustrated herein to manifest in the real world, several regulatory barriers to behind-the-meter energy storage market participation must be overcome.**

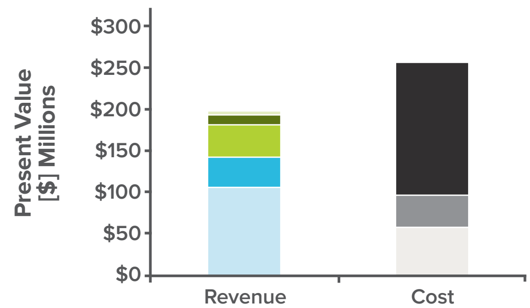
**FIGURE ES3**

BATTERY ECONOMICS GREATLY IMPROVE WHEN SERVICES CAN BE STACKED: FOUR EXAMPLES

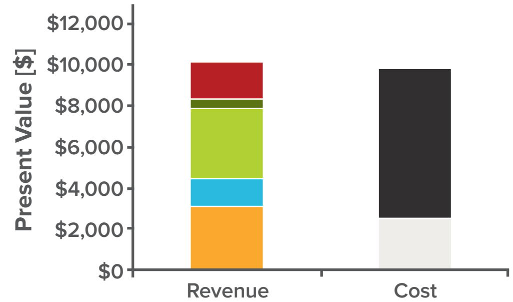
**USE CASE I. Commercial demand-charge management in San Francisco. Primary service:** commercial demand-charge management. **Secondary services:** frequency regulation, resource adequacy, and energy arbitrage.



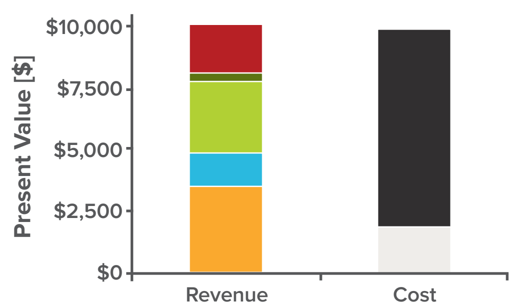

**USE CASE II. Distribution upgrade deferral in New York. Primary service:** distribution upgrade deferral. **Secondary services:** a suite of ISO / RTO services and resource adequacy.




**USE CASE III. Residential bill management in Phoenix. Primary service:** time-of-use optimization / demand-charge reduction. **Secondary services:** a suite of ISO / RTO services and resource adequacy.




**USE CASE IV. Solar self-consumption in San Francisco. Primary service:** solar self-consumption*. **Secondary services:** time-of-use optimization, a suite of ISO/RTO services, and resource adequacy.




**ISO/RTO SERVICES:** Load Following, Frequency Regulation, Spin Reserve, Non-Spin Reserve, Black Start

**UTILITY SERVICES:** Resource Adequacy, Dist Deferral **CUSTOMER SERVICES:** TOU, Self-Consumption, Demand Charge Reduction

**COSTS/TAX:** Capital Cost, O&M & Charging, Tax Cost, Tax Benefits

** This analysis is based on a hypothetical scenario in which net energy metering is replaced with a value-of-solar tariff at 3.5 cents per kWh. While RMI does not think this scenario is likely (nor would we advocate for it) we did want to understand the economics of solar and storage under an avoided-fuel-cost compensation model.*

**Energy storage business models that deliver multiple, stacked services can provide system-wide benefits. With appropriate valuation of those services, such battery business models can also provide net economic benefit to the battery owner/operator.** As illustrated by the three cases analyzed in this report that modify customer load profiles in response to rate structures, energy storage systems deployed for a single customer-facing benefit do not always produce a net economic benefit. However, by combining a primary service with a bundle of other services, batteries become a viable investment.[i] Importantly, the positive economics for bill management scenarios (e.g., demand-charge reduction, time-of-use optimization) even without applying a value to backup power suggests that customers are likely to seek out behind-the-meter energy storage. In light of the fact that these assets can be used to provide grid services on top of this primary use, creating business models that take advantage of this capability—rather than procuring ultimately redundant centralized solutions—should be a high priority for grid operators, regulators, and utilities.

The New York distribution upgrade deferral case was the only one without positive economics examined in this report. However, after delivering the primary service of distribution deferral, if the batteries were secondarily dispatched to deliver customer-facing services, like demand charge reduction or backup power (instead of wholesale market services), the economics would likely flip in favor of storage. Accordingly, this case demonstrates the importance of considering all services, including customer services, when building an economic case for battery storage.

**Batteries are often deployed for primary reasons that use the battery only a small fraction of the time, leaving an opportunity for other, stacked services.** For example, distribution deferral typically demands only 1% of the battery's useful life; demand charge reduction represents a 5–50% utilization rate. Building business models that, at the outset, only plan to utilize batteries for a minority of the time represents a lost opportunity. While the stacked-use business models we analyzed are not necessarily the right ones for all real-world situations, the development of robust stacked-use business models should be a priority for industry.

### *4. What barriers—especially regulatory—currently prevent single energy storage systems or aggregated fleets of systems from providing multiple, stacked services to the electricity grid, and what are the implications for major stakeholder groups?*

**Distributed energy resources such as behind-the-meter battery energy storage have matured faster than the rates, regulations, and utility business models needed to support them as core components of the future grid. Even though behind-the-meter energy storage systems have the potential to economically provide multiple, stacked benefits to all stakeholder groups in the electricity system, many barriers largely prevent them from doing so. In order to address these issues, we recommend the following next steps to enable behind-the-meter energy storage to provide maximum benefits to the grid:**

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*[i] This report considers where batteries should be deployed to enable the broadest suite of multiple, stacked services. The issue of who would make the investment in those batteries—such as customers, utilities, or third parties—remains an open question.*

### For Regulators

- Remove barriers that prevent behind-the-meter resources such as battery energy storage from providing multiple, stacked services to the electricity grid that benefit all stakeholder groups, including customers, ISOs/RTOs, and utilities.[ii]

- Require that distributed energy resources (including storage) be considered as alternative, potentially lower-cost solutions to problems typically addressed by traditional "wires" investments and/or centralized peaking generation investments.

- Across all markets, require utilities to use a standardized, best-fit, least-cost benefit methodology that compares energy storage providing a full suite of stacked services with incumbent technologies.

### For Utilities

- Restructure utility business models and rates to reflect the value that storage can provide to the grid via temporal, locational, and attribute-based functionality, making utilities indifferent to the distinction between distributed and centralized resources.

- Prior to considering new centralized assets, look first for opportunities to leverage existing assets, such as storage, via stacking of uses; provide education so that distribution planners, grid operators, and rate designers can work together to leverage storage's full suite of capabilities.

### For the Research Community

- Develop a widely recognized modeling tool or a consistent methodology and approach capable of comparing, on an equal basis, the net cost of stacked services provided by energy storage and other distributed energy resources as compared to incumbent technologies such as combustion turbines and traditional infrastructure upgrades.

- Develop a detailed state-by-state roadmap that specifically identifies policy and regulatory changes that must be adapted or revised to enable widespread integration of energy storage and other distributed energy resources.

### For Battery and Distributed-Energy-Resource Developers

- Pursue business models that fully utilize the battery.

- Pursue cost reduction efforts for all power-focused elements of energy storage systems (all $/kW components) in order to unlock more energy storage markets.

- Collaborate with utilities and regulators to help them understand what values distributed energy storage can provide and what new utility business models will be needed to scale them.

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[ii] *Ongoing efforts that tend towards this outcome include New York's Reforming the Energy Vision proceeding, California's order for development of distributed resource plans, Massachusetts' Grid Modernization Plan, ERCOT's proposed rules and regulations on distributed energy resource integration, Minnesota's e21 initiative, ongoing regulatory proceedings in Hawaii, and others.*