BEFORE THE LOUISIANA PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF ENTERGY LOUISIANA, LLC FOR CERTIFICATION TO DEPLOY NATURAL GAS-FIRED DISTRIBUTED GENERATION AND AUTHORIZATION TO IMPLEMENT RIDER	**DOCKET NO. U-36105**

CROSS-ANSWERING TESTIMONY OF EDWARD BURGESS

ON BEHALF OF

THE ALLIANCE FOR AFFORDABLE ENERGY

JANUARY 31, 2022

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I. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Can you please summarize your key findings and recommendations?

A. Yes, below is a brief summary of each.

Key Findings:

(1) Entergy Louisiana LLC's ("ELL," "Entergy," or the "Company") proposal unfairly allocates a significant share of the costs of the back-up generators to Non-Host customers (particularly residential customers), without providing commensurate reliability benefits; and

(2) ELL was unreasonable in its dismissal of the potential for a solar plus storage system to provide backup power in lieu of natural gas.

Recommendations:

(1) The Commission should reject ELL's application as proposed.

(2) The Commission should direct ELL to consider modifications to its proposal including:

a) a different approach to cost-allocation,

b) expanded access to non-commercial and -industrial ("C&I") customers, and

c) use of solar plus storage instead of natural gas.

II. INTRODUCTION AND QUALIFICATIONS

Q. State your name, business name and address.

A. My name is Edward Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. On whose behalf are you appearing in this case?

A. I am appearing here as an expert witness on behalf of the Alliance for Affordable Energy ("Alliance").

Q. Summarize your professional and educational background.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to resource planning, transmission planning, renewable energy, energy storage, utility rate design and program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full resume is attached as Exhibit A.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I have testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General's Office ("AGO") at the evidentiary hearings for D.P.U. Docket Nos. 18-150 and 17-140. I have also supported the AGO as a technical consultant in other cases including D.P.U. Docket Nos. 17-05, 17-13, 15-155, and 17-146. I have also testified before the South Carolina Public Service Commission on behalf of the South Carolina Solar Business Alliance in evidentiary hearings for Docket Nos. 2019-186-E, 2019-185-E, 2019-184-E and 2021-88-E. I provided written testimony to the Indiana Utility Regulatory Commission on behalf of the Citizens Action Coalition in two proceedings related to Duke Energy's Fuel Adjustment Clause (IURC Cause Nos. 38707 FAC 123 S1 and FAC 125). I also recently provided testimony to the Nevada Public Utilities Commission on NV Energy's Integrated Resource Plan in Docket No 20-07023. I have testified before the California Public Utilities Commission on behalf in PacifiCorp's 2020 and 2021 Energy Cost Adjustment Clause proceedings, A.19-08-002 and A.20-08-002. I also testified before the Oregon Public Utilities Commission on PacifiCorp's Transition Adjustment Mechanisms in Docket Nos. UE-375 and UE-390. Finally, I have testified before the Washington Utilities and Transportation Commission on Avista Utilities' general rate case (Docket No. UE-200900). Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments, and participating in technical workshops on a wide range of proceedings at Public Utilities Commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission ("FERC"), and at the California Independent System Operator.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to assess Entergy's proposed Natural Gas-Fired Distributed Generation program. I discuss the deficiencies of the program's proposed cost allocation, many of which were also raised in the Direct Testimony of Staff Witness Sisung. I also address other major shortcomings of the program such as the fact that it does not include other viable technologies for providing backup power such as solar plus storage.

Q. Are you providing any exhibits?

A. Yes. My exhibits are as follows:

- Exhibit A: Resume of Edward Burgess, and
- Exhibit B: Strategen, *Assessment of Potential Alternatives for Local Peaking Capacity in the Entergy New Orleans Service Area* (Feb. 2019).

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III. COST ALLOCATION

Q. In LPSC Staff's Direct Testimony, Witness Sisung states "I do not find the costs and benefits of the program are being allocated in a manner that is just and reasonable to Non-Host Customers."[1] Do you agree?

A. Yes. As Mr. Sisung's testimony makes clear, the Company's proposal would result in a limited number of Host Customers' being the beneficiaries of backup generation services that are heavily subsidized by the Non-Host Customers.

Q. What are some of the issues identified by Staff in which Non-Host Customers are cross-subsidizing the costs of the program for the benefit of the Host Customers?

A. Some of these cross subsidies are described below:

- Fuel Costs: As Mr. Sisung explained, the gas used to fuel the backup power facilities during a critical event such as a winter storm is likely to be much more expensive than normal. However, the Host Customers would likely not be exposed to these higher costs and instead they would be recovered predominately from Non-Host Customers through the Fuel Adjustment Clause ("FAC") mechanisms. Specifically, Mr. Sisung stated: "…the Power Through Program would allow the Host Customer to pay the lower FAC rate for the period of backup operations … leaving the higher cost of gas for the actual period of backup service left for the Non-Host Customers to absorb in a future FAC as they take their regular service."[2]

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[1] Direct Test. of R. Lane Sisung on Behalf of the LA Pub. Serv. Comm'n, at 25:22–26:1 (Dec. 21, 2021) (Public Version) ("Sisung Direct").
[2] *Id.* at 25:11–15.

- Additional Development Costs: Mr. Sisung points out that the costs ELL proposes to assign to Non-Host Customers appear to include not just the equivalent cost to install a gas combustion turbine ("CT"), but it also includes amounts to cover additional "development costs" whose purpose is unclear and assignment to Non-Host Customers is not justified.
- Future Capital Costs: Mr. Sisung notes that ELL's application and supporting material does not specify how future capital expenditures needed to maintain operations at the new generators would be allocated.[3] As such, these future capital expenditures would presumably be borne by Non-Host Customers.
- Wholesale Margins: Staff notes that only a portion (approximately 60%) of the margins on wholesale sales would be credited to Non-Host Customers under ELL's proposal.[4] Presumably this would include revenues not only from Midcontinent Independent System Operator ("MISO") energy markets but also from capacity markets. Thus, despite paying for the equivalent of a CT, the Non-Host Customers are not receiving the full benefit from these wholesale sales that they normally would if a standard CT unit were used. Instead, the sales margins are being used to further subsidize the Host Customer's contribution.

Thus, taking into account all of these factors, similar to Mr. Sisung, I find this overall arrangement to be unjust and inequitable, and that it departs from the long-standing principle of utility ratemaking that the "beneficiary pays" or "cost-causer pays."

[3] *Id.* at 18:9–10.
[4] *Id.* at 24:7–8.

Q. Can you elaborate on "beneficiary pays" principle?

A. Yes. Generally speaking, this principle holds that costs should be allocated based on who benefits from them or otherwise causes those costs to be incurred. This concept is infused into many of FERC's landmark orders including Order 890,[5] Order 1000,[6] and Order 745.[7] This was reinforced by the landmark court decision in *ICC v. FERC,* which states:

> The Federal Power Act requires that the fee be "just and reasonable," and therefore at least roughly proportionate to the anticipated benefits to a utility of being able to use the grid. Thus "all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them." Courts "evaluate compliance [with this principle, called "cost causation"] by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.

721 F.3d 764, 770–771 (7th Cir. 2013).

As I mentioned earlier, I believe ELL's proposal deviates from this principle.

Q. Aside from the inequities that Staff has identified, do you believe there are other inequities in the costs borne by Non-Host Customers and benefits they receive?

A. Yes. As I understand ELL's proposal, Non-Host Customers would initially be responsible for incremental costs equivalent to a new CT, which ELL estimates to be $77.99/kW-year on a levelized cost basis.[8] For the full 120 MW, ELL estimates a net revenue requirement

[5] *Preventing Undue Discrimination and Preference in Transmission*, 118 FERC ¶ 61,119, at P 559 (Feb. 16, 2007) ("…when considering a dispute over cost allocation, [the Commission exercises its] judgment by weighing several factors. First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them").
[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, 136 FERC ¶ 61,051, at P 626 (July 21, 2011) ("a departure from cost causation principles can result in inappropriate cross-subsidization. This is why cost causation is the foundation of an acceptable cost allocation method").
[7] *Demand Response Compensation in Organized Wholesale Energy Mkts.*, 134 FERC ¶ 61,187, at PP 100–102 (Mar. 15, 2011).
[8] Direct Test. of Jonathan R. Bourg on Behalf of Entergy, at 33 (July 2021) (Public Version).

increase of approximately $18 million per year,[9] or $360 million over 20 years. However, despite incurring these costs, it is far from certain that Non-Host Customers will actually receive reliability benefits commensurate with the installation of new CT.

Q. Can you elaborate on why Non-Host Customers may not receive the CT-equivalent of reliability benefits?

A. Yes. In this case, ELL has characterized the reliability benefit that Non-Host Customers receive through the program as the equivalent of a new CT built for resource adequacy purposes. However, it's not clear to me that the reliability benefit to Non-Host Customers would truly be equivalent. If a generation shortfall were to occur due to high summer demand (i.e., resource inadequacy), ELL's system operators would likely resort to curtailing power in some portions of the grid while continuing to serve other portions. Since the very nature of this program is to install generators at a limited number of Host Customer locations, there is a much greater likelihood that the Host locations will be powered under generation shortfall conditions rather than Non-Host Customer locations. In such a case, the reliability benefits may not be shared equally between Host and Non-Host customers. This is true even for reliability issues that occur outside of catastrophic events (such as a major hurricane) and arise simply due to high load conditions.

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[9] Direct Test. of Crystal K. Elbe on Behalf of Entergy, Ex. CKE-2 (July 2021) (Public Version).

Q. You have described numerous inequities that the proposed Power Through program would create between Host and Non-Host customers. Are there steps that ELL could have taken to create a more balanced program design?

A. Yes. A major flaw in the program design is that its benefits are limited to C&I customers who choose to become Hosts, while the costs are largely subsidized by residential customers that are Non-Hosts by default. Hypothetically, ELL could have designed a program that included a similar offering for residential customers. For example, the Company could have offered to install solar photovoltaic ("PV") plus battery backup systems at residential homes. The cost to participate could be formulated in the same way as the Company's proposal such that residential host sites would only pay the portion of project costs above the $77.99/kW-year CT-equivalent. The residual $77.99/kW-year in costs could then be assigned to C&I customers, and other Non-Host residential customers.

Q. Do you think a Utility-Owned Distributed Generation ("UODG") program should be approved if this modification were made?

A. Not necessarily, however, it could be an improvement from a fairness standpoint by expanding access to a greater number of customers. My main purpose in providing this hypothetical example is to illustrate the inherent unfairness and asymmetry of the ELL program as proposed. Specifically, the program benefits a small number of C&I customers, while being cross-subsidized by residential customers, and while not providing an equal opportunity for residential customers to achieve the same benefits.

Q. Do you believe the goals of the program—to provide backup power to critical facilities such as hospitals and government buildings—is worth pursuing?

A. Yes. However, I think there are better ways to achieve what ELL has proposed, both in terms of cost allocation as well as the technologies used to achieve this goal.

IV. ALTERNATIVE TECHNOLOGIES NOT CONSIDERED

Q. Aside from the fairness and cost allocation issues you have described thus far, what other shortcomings are there in the proposed UODG program?

A. A major shortcoming is the narrow and exclusive focus on natural gas generation technologies.

Q. Do you believe other technologies should have been included or even preferred in lieu of natural gas?

A. Yes. It is well known that significant improvements have been made in recent years to the cost and performance of solar PV and battery storage technologies. In fact, depending on the configuration, a hybrid solar plus storage resource can be cost competitive with traditional generation technologies such as natural gas.

Q. Have you performed any analysis to demonstrate this cost-competitiveness?

A. Yes. As shown in Exhibit B, I performed a briefing of an analysis in 2019 comparing the net cost of a battery resource to a reciprocating engine peaker, similar to the ones contemplated in ELL's proposal. This analysis was performed on behalf of the Alliance and provided to the New Orleans City Council as part of its deliberations on the proposed (at the time) New Orleans Power Station. The charts excerpted from this briefing below demonstrate that the battery storage resource could outperform the reciprocating engine.

Moreover, this analysis does not consider the possibility of a co-located solar resource which could improve the economics by providing increased energy value and allowing the federal solar investment tax credit to be leveraged.

Figure 1: Illustrative net cost comparison of a 128 MW natural gas peaker and 128 MW, 4-hour, battery energy storage.

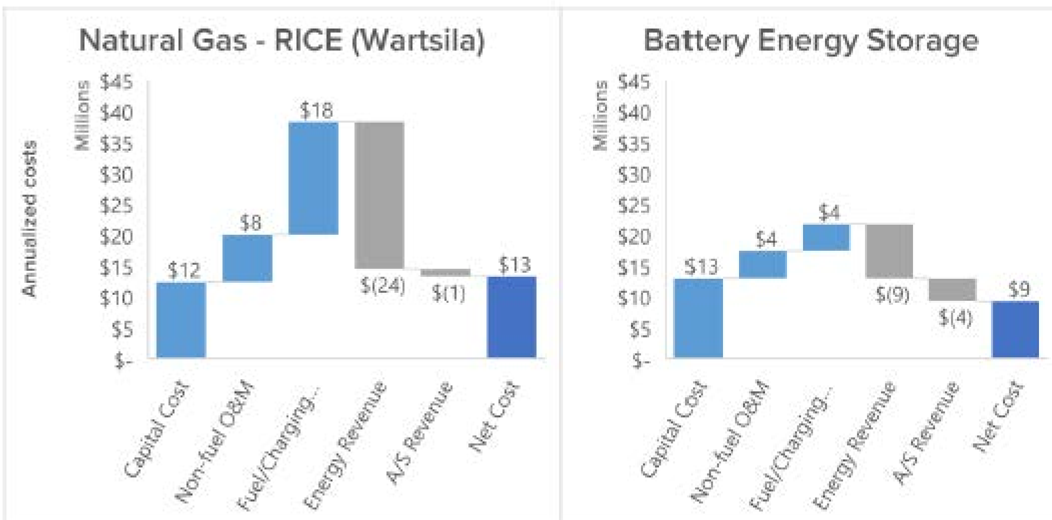


Figure 2. Illustrative net cost comparison of a 128 MW natural gas peaker (left) and 128 MW, 4-hour, battery energy storage (right). Peaker capital and fuel costs based on the ENO Alternative Peaker (Wartsila) and Battery capital costs (low case) shown in Table 1. Energy revenue and charging costs based on 2017-18 MISO Louisiana Hub price data. Assumes Ancillary Services revenue for battery from regulation at $5/MW-h and for peaker from spinning reserves at $2/MW-h.

[10]

Q. Wouldn't a solar plus storage resource provide less of a reliability benefit than a natural gas resource that can provide continuous power?

A. Not necessarily. The ability for solar plus storage to provide continuous power partly depends on the magnitude of the load being served, the size of the solar component, and the duration of the battery. Depending on these factors, a solar plus storage system may still be able to continuously supply backup power to critical loads for several days during emergency conditions while power is being restored. This may depend on the specific site

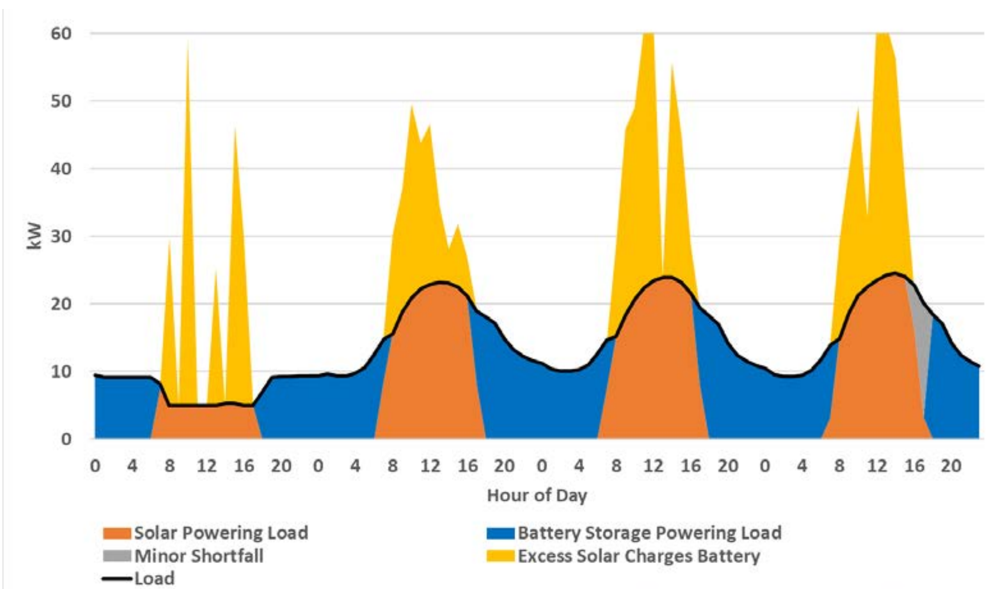
[10] Ex. B at 4.

in question and their usage patterns. Unfortunately, ELL appears to have dismissed the possibility of using solar plus storage without doing any supporting analysis.

Q. Have you performed any analysis on the potential for solar plus storage to provide continuous backup power capabilities to a C&I load in Louisiana?

A. Yes. Below is a chart of a simulation I performed for a representative C&I facility in Louisiana being powered solely by solar plus storage facilities over the course of four days in February. This is intended to show what could feasibly occur if such a site were to rely on solar plus storage for backup power instead of natural gas. Notably the solar plus storage system is able to provide continuous backup power for nearly all of the hours over this four-day stretch representing over 98% of the site's power needs. Under emergency conditions, this should be more than sufficient to power the facility's critical loads, presuming the site took steps to minimize unnecessary consumption.

Figure 2: Simulated Solar + Storage Providing Backup Power to a C&I Load in Louisiana for 4 Days in February.



Q. Doesn't the chart show a minor shortfall on the fourth day?

A. Yes. This represents only 2% of the site's load over this time period. I also believe this could be easily alleviated by increasing the size of the battery or managing the site's load.

Q. What input data and assumptions did you use to conduct this simulation?

A. I used the following assumptions:

- The solar PV system was sized to be a 61kW system, paired with a 61kW, four-hour duration battery storage system. The solar was sized to provide the annual energy equivalent to the site's load.
- The hourly solar generation profile was calculated with the PVwatts tool using TMY3 data from the National Solar Radiation Database. The location chosen was the New Orleans International airport.
- The hourly load profile was based on the publicly available "Comstock" dataset maintained by the National Renewable Energy Laboratory, adjusted to reflect an individual C&I facility.

Q. Are there reliability advantages to using solar plus storage for backup power instead of natural gas?

A. Yes. Most importantly, solar plus storage would not be subject to potential fuel supply disruptions that could affect natural gas supply during a catastrophic event. For example, during Winter Storm Uri in February 2021, a major reason for the extensive outages in Electric Reliabilty Council of Texas ("ERCOT") and MISO was a steep decline in the availability of natural gas fuel to power generation facilities. This was due to the fact that wellheads and related infrastructure were typically not hardened for freezing conditions and ice accumulation. In fact, Texas natural gas production fell by almost half during the storm.[11] Output at many processing plants even fell to zero. Natural gas facilities installed by ELL at Host-Sites would be exposed to these same risk factors, and may find that natural gas is unavailable or cost-prohibitive when it is most needed for backup power.

Q. Are there other reasons why a solar plus storage technology might be preferred over natural gas?

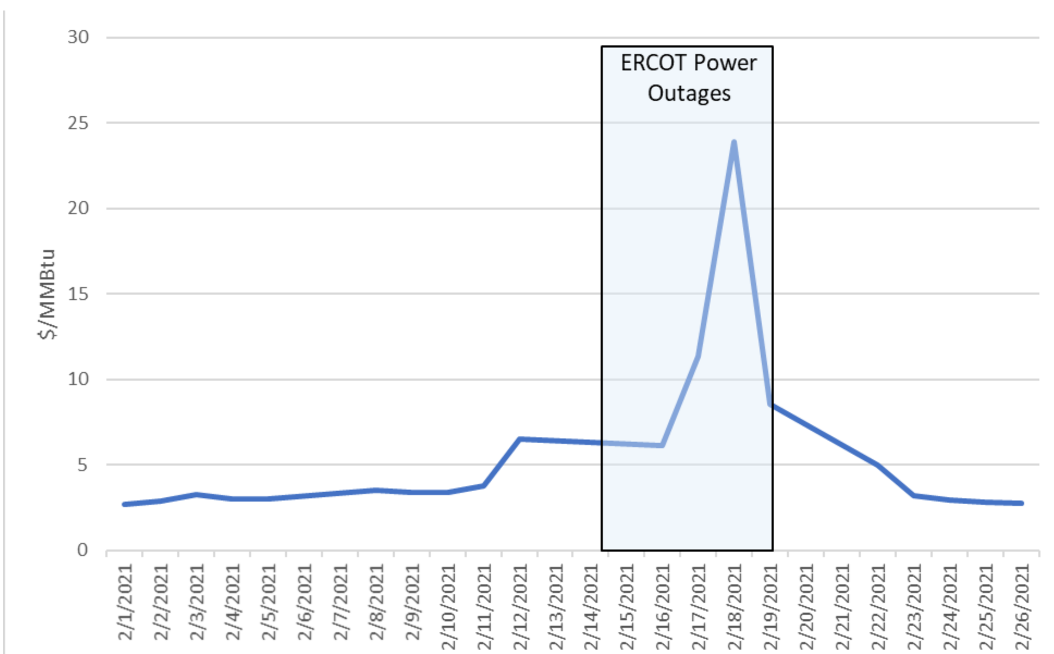
A. Yes, there are several. First, customer preference surveys typically show overwhelming support for solar energy relative to other resources.[12] Thus, if Non-Host customers are being forced to subsidize some form of backup power, it would be sensible to choose a form of power that they prefer. In fact, many large C&I customers that might be eligible to participate in ELL's proposed program may also have corporate or municipal sustainability goals that require them to meet a certain percentage of their energy needs from renewable resources. Providing power via natural gas would only work against meeting those sustainability goals. Second, as non-emitting resources, solar plus storage would not generate any localized pollution that could harm public health. This is especially important to consider for facilities like hospitals where the emissions would be in close proximity to vulnerable and sensitive populations. Third, use of renewable energy would be more consistent with the goals of Governor Bel Edwards Climate

[11] Energy Inst., *The Timeline and Events of the Feb. 2021 Texas Elec. Grid Blackouts*, The University of Texas, at Austin (July 2021), https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%20020210714.pdf.

[12] Pew Rsch. Center, *Two-thirds of Americas give priority to developing alternative energy over fossil fuels*, Brian Kennedy (Jan. 23, 2017), https://www.pewresearch.org/fact-tank/2017/01/23/two-thirds-of-americans-give-priority-to-developing-alternative-energy-over-fossil-fuels/.

Initiatives Task Force which was established to "reduce the greenhouse gas emissions that are driving up global temperatures, increasing sea level and other risks that threaten our health and safety, quality of life, economic growth, and vital habitats and ecosystems."[13] Finally, solar plus storage is not subject to any form of fuel price risk. As Staff's testimony astutely noted, "A very likely occurrence of backup service will be that when the service is being provided it will be in times of system-wide stress when natural gas prices will be inordinately high."[14] The chart below illustrates this risk by showing how the price of natural gas spiked significantly and coincided with the ERCOT power outages during Winter Storm Uri.

Figure 3: Simulated Solar + Storage Providing Backup Power to a C&I Load in Louisiana for 4 Days in February



[13] Office of the Governor—John Bel Edwards, *Climate Initiatives Task Force*, https://gov.louisiana.gov/page/climate-initiatives-task-force (last visited Jan. 28, 2022).
[14] Sisung Direct at 25:6–8.

Moreover, Staff explains that some of these increased fuel costs are likely to be absorbed by Non-Host Customers, thus exacerbating the degree of cross-subsidies embedded in the Power Through Program. Using a solar plus storage resource instead would eliminate this fuel price risk and also eliminate the potential cross subsidy involved in the FAC fuel cost recovery.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT A

Resume of Edward Burgess

Edward Burgess

Senior Director

STRATEGEN

Ed leads the integrated resource planning practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. He has led or contributed to expert testimony, formal comments, technical analyses, and strategic grid planning efforts for clients in over 25 states. These have focused on a range of topics including resource planning and procurement, utility system operations, transmission planning, energy storage, electric vehicles, utility rates and rate design, demand-side management, and distributed energy resources.

Contact

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Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

BA
Chemistry
Princeton
2007

STRATEGEN.COM

Work Experience

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system planning via economic analysis, technical regulatory support, integrated resource planning and procurement, utility rates, and policy & program design.
+ Supports clients such as trade associations, project developers, public interest nonprofits, government agencies, consumer advocates, utilities commissions and more.

Senior Policy Director

Vehicle-Grid Integration Council / Berkeley, CA / 2019 - Present

+ Leads advocacy and regulatory policy for a group representing major auto OEMs and EVSEs
+ Advances state level policies and programs to ensure the value from EV deployments and flexible EV charging and discharging is recognized and compensated
+ Leads all policy development, education, outreach, and research efforts

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Edward Burgess

Senior Director

STRATEGEN

Selected Recent Publications

+ New York BEST, 2020. *Long Island Fossil Peaker Replacement Study.*
+ Ceres, 2020. *Arizona Renewable Energy Standard and Tariff: 2020 Progress Report.*
+ Virginia Department of Mines and Minerals, 2020. "*Commonwealth of Virginia Energy Storage Study.*
+ Sierra Club, 2019. *Arizona Coal Plant Valuation Study.*
+ Strategen, 2018. *Evolving the RPS: Implementing a Clean Peak Standard.*"
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.*

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

+ Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
+ Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

+ Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003)
+ Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

+ Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

+ Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Edward Burgess

Senior Director

STRATEGEN

Relevant Project Experience (con't)

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 - 2020

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
+ Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
+ Worked with Strategen technical team on utilizing a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 - 2019

+ Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage

Portland General Electric

Energy Storage Strategy / 2016

+ Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
+ Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
+ Supported development of a competitive solicitation process for storage technology solution providers.

Xcel Energy

Time-of-use Rates / 2017 - 2018

+ Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

+ Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
+ Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 - 2021

+ Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
+ Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 - 2017

+ Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
+ Conducted study on the use of storage as an alternative to natural gas peaker.
+ Presented workshop and study findings before the Minnesota Public Utilities Commission.

Edward Burgess

Senior Director

STRATEGEN

Expert Testimony

California Public Utilities Commission

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)

Indiana Utility Regulatory Commission

- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause – Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Massachusetts Department of Public Utilities

- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Nevada Public Utilities Commission

- NV Energy's Integrated Resource Plan in (Docket No 20-07023)

Oregon Public Utilities Commission

- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)

South Carolina Public Service Commission

- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Washington Utilities and Transportation Commission

- Avista Utilities General Rate Case (Docket No. UE-200900)

EXHIBIT B

Strategen, *Assessment of Potential Alternatives for Local Peaking Capacity in the Entergy New Orleans Service Area* (Feb. 2019)

Assessment of Potential Alternatives for Local Peaking Capacity in the Entergy New Orleans Service Area

Prepared by Strategen Consulting for: Alliance for Affordable Energy & Clean Energy Group. February 2019

Background

Entergy New Orleans (ENO) has recently sought approval from the New Orleans Council to build the New Orleans Power Station (NOPS), comprised of either a new 226 MW peaking natural gas-fired combustion turbine (MHPSA), or alternatively 128 MW of gas-fired reciprocating engines (Wartsila) at the Michoud site. ENO's original Application and Supplemental and Amending Application outline ENO's assessment of need for local generation and provide analysis of potential alternatives. While comprehensive in many ways, Strategen finds that ENO's analysis overlooks certain options. Most importantly, ENO did not conduct a serious analysis of battery storage or solar PV + storage as alternatives for meeting ENO's need. ENO's Applications each included only a single reference to storage resources in relation to their use for intermittent resources:

> "However, without cost-effective storage, which does not exist at this time, it is not possible to utilize intermittent resources to meet ENO's capacity reserve needs and, in turn, ensure reliable service to customers."[1]

In this briefing, Strategen provides up-to-date information on the status of grid connected battery storage projects. We report on the cost-effectiveness and value of recent or proposed storage projects. Additionally, we provide a comparison of a comparable storage project to the ENO-proposed NOPS gas peaker facility (MHPSA) and Alternative Peaker (Wartsila).[2]

Recent Energy Storage Project Examples

The market for grid-connected energy storage devices has evolved considerably over the last few years. Globally, there is now a significant number of commercial, large-scale battery storage projects that are online, under construction, or are contracted to be built. Below are a few examples of some of these recent projects:

Standalone Storage Project Examples:

- In June 2018, Pacific Gas & Electric (PG&E) entered long-term contracts for over 567 MW of battery storage resources including:
  - A 300 MW, 4-hour duration battery
  - A 75 MW, 4-hour duration battery
  - A 182.4 MW, 4-hour duration battery

  In its filing to the Public Utilities Commission, the PG&E determined that the storage solutions were cost-effective as an alternative to extending a "Reliability Must-Run" contract with a gas plant that would otherwise be needed for local reliability.[3]

[1] Council of the City of New Orleans, Docket No. UD-16-02, *Supplemental and Amending Application of Entergy New Orleans, Inc. For Approval to Construct New Orleans Power Station*, at page 19.
[2] Strategen recognizes that some of the information provided in this briefing may not have been available to ENO at the time of its Application or Supplemental Application. However, Strategen has included these materials in the interest of bringing the most current information to the Council's attention.
[3] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M229/K550/229550723.PDF

- In 2016, Southern California Edison and San Diego Gas & Electric conducted an expedited solicitation for battery storage projects to address local grid reliability issues related to a gas leak the Aliso Canyon gas storage facility. As a result, three large-scale storage projects totaling 70 MW were brought online in less than 1 year.[4]
- In May 2018, Salt River Project (Arizona's largest electric utility) entered a 20-year contract for a 10 MW, 4-hour duration battery to provide peaking capacity during periods of high demand.[5]
- In November 2017, the MW Hornsdale Power Reserve project was energized in South Australia. This 100 MW battery built by Tesla Inc. has provided frequency regulation services that have helped stabilize the grid as well as provide load shifting.[6]

Solar + Storage Project Examples:

- In January 2019, Minnesota electric cooperative Connexus began commercial operation of a 10 MW solar + 15 MW battery storage facility. The coop found the project to be cost effective with an expected payback of 7-8 years due to demand savings.[7]
- In December 2018, the Nevada Public Utility Commission approved three solar + storage PPAs proposed by NV Energy, all for 2021 delivery:[8]
  - A 101 MW solar + 25 MW battery (4-hour) facility with a PPA price of $26.50/MWh
  - A 200 MW solar + 50 MW battery (4-hour) facility with a PPA price of $26.51/MWh
  - A 100 MW solar + 25 MW battery (4-hour) facility with a PPA price of $29.96/MWh
- In 2017, Xcel Energy in Colorado conducted an All-Source Solicitation for new resources and received several bids for hybrid solar + storage resource. The median bid PPA price received for this type of resource was $38/MWh.[9] Notably, the solar + storage projects in Nevada and Colorado have a significantly lower levelized cost of energy (LCOE) than the alternatives considered by ENO.[10]
- In New England, the company Sunrun (which provides customer-sited distributed solar and battery storage) recently won a 20 MW bid in the forward capacity auction for ISO New England, which operates the electric grid in six Northeastern states. That auction results demonstrate the ISO's expectation that Sunrun will be able to deploy enough solar and storage to provide 20 MW of reliable grid capacity by 2022.[11]

Cost Comparison: NOPS Peaker versus Standalone Storage

Gross Capital Cost Comparison

There are several ways to evaluate the costs of new energy resources. One simple method is to compare the installed cost on a $/kW basis. In its Supplemental Application, ENO provided a cost comparison for five different natural gas peaker options. The installed costs for these ranged from

[4] https://www.greentechmedia.com/articles/read/aliso-canyon-emergency-batteries-officially-up-and-running-from-tesla-green#gs.HJykJYKB
[5] https://www.srpnet.com/newsroom/releases/053018.aspx
[6] https://en.wikipedia.org/wiki/Hornsdale_Wind_Farm#Hornsdale_Power_Reserve
[7] https://www.utilitydive.com/news/minnesota-co-op-breaks-ground-on-first-major-storage-projects-in-state/529512/
[8] http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-6/30441.pdf
[9] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=881732&p_session_id=
[10] In its testimony, ENO presented its analysis for recommending the alternative peaker, which include 5 gas peaker technology options with a LCOE ranging from $75-89/MWh. See Table 1 on p 10 of Supplemental and Amending Testimony of Jonathan E. Long.
[11] https://www.greentechmedia.com/articles/read/sunrun-wins-new-england-capacity-auction-with-home-solar-and-batteries#gs.EnD76B0I

$803/kW to $1,045/kW.[12] Meanwhile, Strategen estimates that the cost to install a standalone battery storage facility designed to provide peaking power in the 2020 timeframe could be as low as $989/kW, which is well within the range of alternatives considered by Entergy (see Table 1).

On a levelized cost basis, including fuel and O&M costs, Strategen estimates that the range of storage resource costs is likely to be lower than those considered by ENO. Additionally, recent publicly available bid prices for standalone storage projects to be delivered by 2023 have demonstrated even more competitive pricing, with Xcel Energy (Colorado) reporting $136/kW-yr and NIPSCO (Indiana) reporting $135/kW-yr.[13] Notably, these represent actual bid prices by competitive suppliers, not hypothetical assumptions about future costs.

Table 1. Cost comparison for peaking resource options

Technology	Est. Delivery Year	Est. Initial Capital Cost $/kW	Est. Lifetime Levelized Costs $/kW-yr	Emissions, NOx & CO (ppm)	Groundwater Withdrawal
Proposed Gas Peaker (MHPSA)[14]	2019	$803	$304[15]	5/9	Very Low
Alternative Gas Peaker (Wartsila)[16]	2019	$942	$317[15]	5/15	Very Low
Other Gas Peaker (LM6000 PF)[17]	2019	$1,045	$313[15]	5/15	57
Storage – Low	2020	$989[18]	$175[19]	0	0
Storage – High	2020	$1,558[18]	$252[19]	0	0
Storage (Xcel bid price)	2023	--	$136	0	0
Storage (NIPSCO bid price)	2023	--	$135	0	0

Net Cost Comparison

Peaker plants, like the proposed NOPS project, are generally designed to operate infrequently, and often have capacity factors of less than 10%. Thus, while providing peak capacity during critical hours, these facilities provide little additional value in terms of energy or other grid services during most of the year. In contrast, an energy storage system, once installed, can efficiently provide value to the grid during many hours of the year, not simply during peak load hours. It is important to consider these additional values when evaluating a resource's cost-effectiveness. This can be done by

[12] See Table 1 on p 10 of Supplemental and Amending Testimony of Jonathan E. Long.
[13] https://www.ourenergypolicy.org/wp-content/uploads/2018/10/14618_economic_potential_for_storage_in_nevada_-_final.pdf
[14] Based on ENO's reported information for the M501F3 (MHPSA) unit, which is proposed by ENO.
[15] Includes capital cost, fuel (based upon 4000 hours per year dispatch and $3.50/MMBtu gas, consistent with Direct Testimony of Jonathan E. Long) escalated at 2%/yr, non-fuel O&M (based on Exhibits OT-1R & OT-2), and LTSA (based on Direct Testimony of Jonathan E. Long). Assumes a lifetime of 20 years and WACC of 8%.
[16] Based on ENO's reported information for the Wartsila Alternative Peaker unit.
[17] Based on ENO's reported information for the GE LM6000 PF Sprint 25 x3 units + evap cooler.
[18] Storage costs are based upon Lazard's Levelized Cost of Storage Analysis, Version 4.0 (2018): https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.
The reported installed cost range reflects the Li-ion battery wholesale use case (100 MW, 400 MWh). 2018 initial capital costs – DC: $232-398/kWh, Initial Capital Cost – AC: $49-61/kW, and EPC Costs: $16 M. Assumes DC costs (i.e. battery packs) decline from 2018 levels to 2020 levels at the forecasted rate of -8% CAGR.
[19] Includes capital costs and charging costs. Assumes O&M and warranty annual cost equal to 3% of initial cost. Assumes daily cycling and average power purchase price of $23.50/MWh (based on 2017-18 MISO LA Hub price data). Assumes a lifetime of 20 years and WACC of 8%.

comparing the Net Cost, which includes the initial capital cost and O&M, net of energy value (i.e. from arbitrage) and ancillary services value (e.g. frequency regulation).

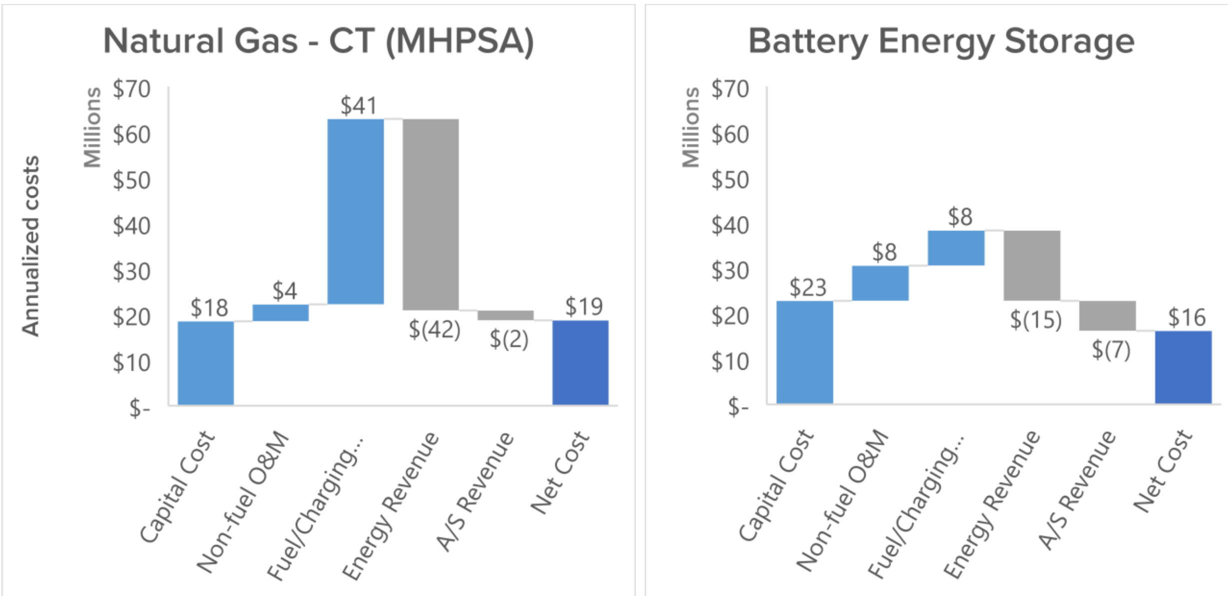

Figure 1. Illustrative net cost comparison of a 226 MW natural gas peaker (left) and 226 MW, 4-hour, battery energy storage (right). Peaker capital and fuel costs based on the ENO-Proposed Gas Peaker (MHPSA) and Battery capital costs (low case) shown in Table 1. Energy revenue and charging costs based on 2017-18 MISO Louisiana Hub price data. Assumes Ancillary Services revenue for battery from regulation at $5/MW-h and for peaker from supplemental reserves at $1/MW-h.

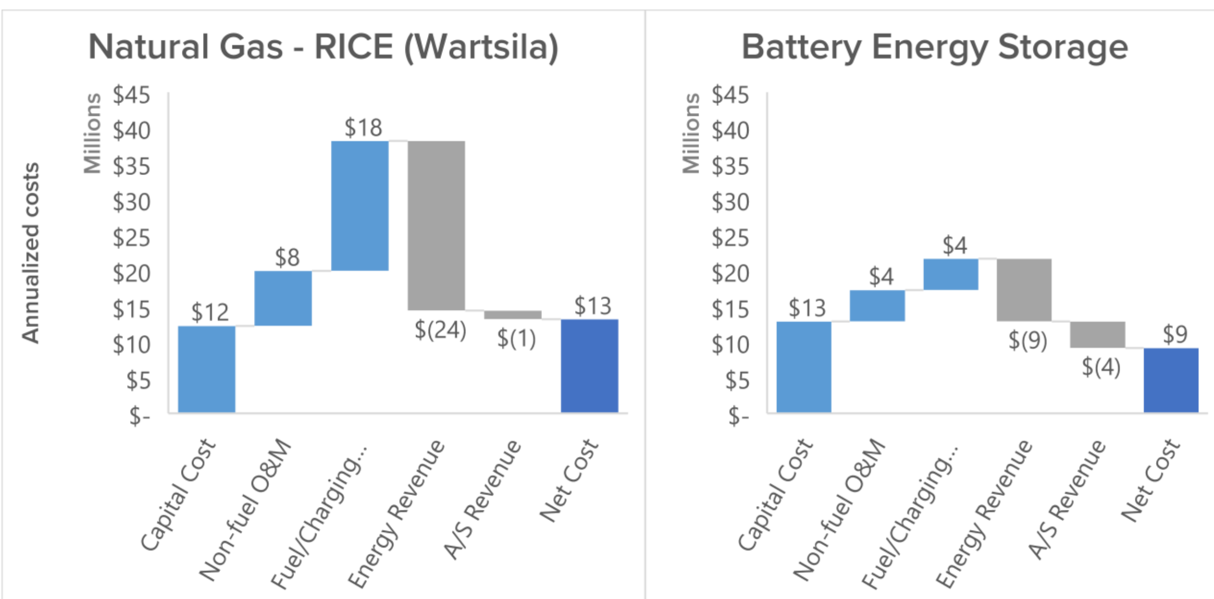

Figure 2. Illustrative net cost comparison of a 128 MW natural gas peaker (left) and 128 MW, 4-hour, battery energy storage (right). Peaker capital and fuel costs based on the ENO Alternative Peaker (Wartsila) and Battery capital costs (low case) shown in Table 1. Energy revenue and charging costs based on 2017-18 MISO Louisiana Hub price data. Assumes Ancillary Services revenue for battery from regulation at $5/MW-h and for peaker from spinning reserves at $2/MW-h.

Option Value

A major advantage of storage is its modular design meaning that incremental additions can be made as needed. Notably, there is always substantial uncertainty in future load growth as demonstrated by ENO's revised load forecast. For traditional power plants that are larger in size (e.g. greater than 200 MW), this presents a challenge since it often necessitates some amount of "overbuild" until load growth catches up to the installed capacity. In contrast storage can be added relatively quickly as needed or avoided altogether if load growth does not materialize. This reduces the risk of overbuilding thereby providing additional "option value" to ENO customers by avoiding costs of a large generator that could become "locked in" even when load growth is less than anticipated.

Subsidence Issues

A major consideration for new power projects sited in the New Orleans area is the effect of subsidence – including potential exacerbation of this issue through groundwater withdrawal.

ENO provided extensive testimony demonstrating that "groundwater withdrawal associated with the Alternative Peaker, like the CT, will not exacerbate subsidence or cause damage to infrastructure in New Orleans East."[20] It should be noted for comparison that a battery energy storage projects would require no groundwater withdrawal, thus would not pose any risk (even an insignificant one) of increased subsidence.

Additionally, even if a facility such as a CT is not a major contributor to subsidence, there is always a possibility it could become affected by subsidence in the future due to other circumstances. Energy storage projects provide an advantage in this regard since they can be relatively easily relocated. Recent examples of battery storage projects that have been relocated include the following:

- AES' 16 MW battery storage facility relocated to Ohio:
    - https://blog.fluenceenergy.com/aes-to-expand-energy-storage-presence-in-pjm-market-with-first-advanced-energy-storage-facility-in-ohio
- ConEd's 4 MWh mobile battery storage pilot program:
    - https://www.utilitydive.com/news/coned-nrg-partner-on-4-mwh-mobile-battery-storage-demo-for-rev-docket/437125/

Storm Resilience

A significant value that battery storage projects can provide is the ability to enhance resilience of the grid during catastrophic events like hurricanes. A real-world demonstration of this occurred during Hurricane Irma in the Dominican Republic. Two large battery storage projects installed on the island were able to help stabilize grid frequency, and alleviate fluctuations caused when 40% of the generation fleet had suffered an outage. Figure 3 (right) illustrates the relatively stable grid frequency during the storm despite significant fluctuations in power output.

[20] Supplemental and Amending Direct Testimony of Dr. George Losonsky at p 6.

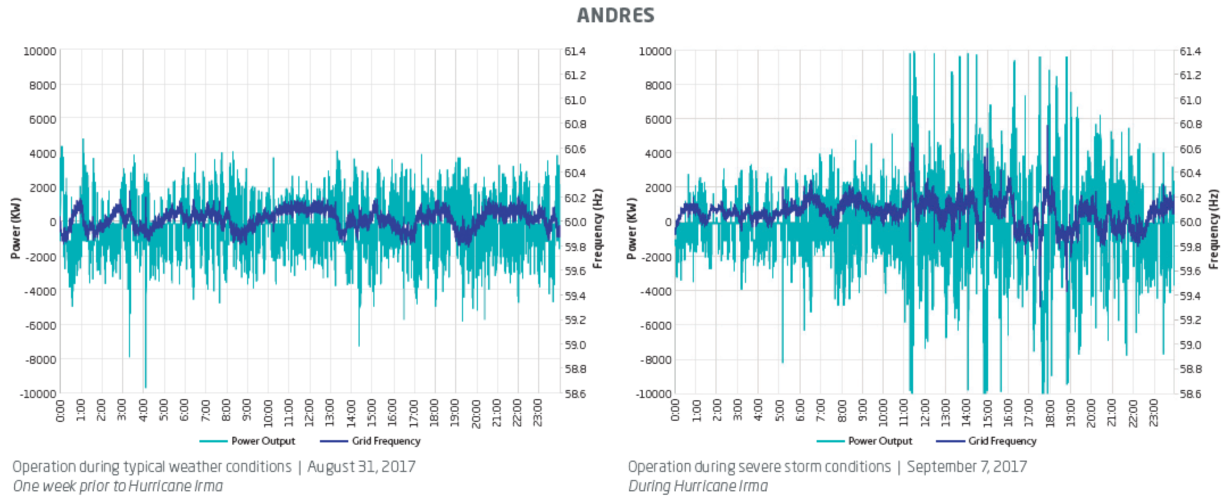

Figure 3. Demonstration of battery storage operation during Hurricane Irma.[21]

Recent studies have also shown that inverter-based resources (like batteries) can actually respond faster and more accurately than traditional generators in the face of a disturbance.[22] Additionally, some cities are currently seeking to deploy solar + storage at critical facilities (e.g. emergency shelters) to provide backup power during an emergency. Examples include the following:

- MA Community Clean Energy Resiliency Initiative[23] -
- San Francisco's Solar Resilient program.[24]
- Maryland Energy Administration Resiliency Hub program[25]

Reliability

Even though they are duration-limited, energy storage resources are able to meaningfully contribute to system reliability in the same manner as a traditional power plant. MISO recently reaffirmed this in its testimony to the Federal Energy Regulatory Commission (FERC) to comply with Order 841. As MISO stated, storage resources are able to qualify as capacity resources so long as they are able to operate for four consecutive hours:

"MISO's proposal modifies the definition of 1 Use Limited Resource and Section 69A.3.1.d of the Tariff to allow Electric Storage Resources to qualify as Use Limited Resources to the extent they are able to operate for a minimum of four consecutive operating Hours across the daily coincident peak for each day."[26]

This is consistent with other system operators which typically assign full or nearly full capacity credit to storage of at least four hours duration. As mentioned above, PG&E recently selected battery storage as a cost-effective option to address local reliability issues in place of an uneconomic gas plant.

[21] https://cdn2.hubspot.net/hubfs/2810531/Collateral/AES%20Collateral/Fluence%20Case%20Study%20-%20Storm%20Resilience.pdf
[22] https://www.nrel.gov/docs/fy17osti/67799.pdf
[23] https://www.mass.gov/community-clean-energy-resiliency-initiative
[24] https://sfenvironment.org/solar-energy-storage-for-resiliency
[25] https://energy.maryland.gov/Pages/Resiliency-Hub.aspx
[26] https://elibrary-backup.ferc.gov/idmws/common/downloadOpen.asp?downloadfile=20181203%2D5244%2833269198%29%2Epdf&folder=7790360&fileid=15109008&trial=1

Recommendations:

Given the advancements in the state of battery storage leading up to and since ENO's application, it appears warranted to revisit the viability of this option in lieu of the proposed alternative. The Council should require Entergy to conduct an all-source RFP solicitation that clearly defines system needs and would be open to a variety of resources including (but not limited to), energy storage, solar + storage, and demand response. This would allow for broad market participation to determine the most cost-effective mix of resources able to fulfill Entergy's peak capacity and reliability needs.

Appendix: Overview of Strategen

Strategen Consulting is a strategic advisory firm that provides insight to global corporations, utilities, public sector leaders, research institutions, technology providers, project developers, and large energy users, helping them to develop impactful and sustainable clean energy strategies. Our clients come to us for our expertise in developing business models, commercial strategies, financing tools and regulatory support that empower them to create sustainable value and long-term solutions. Strategen's exclusive focus on clean energy and advanced grid technologies enables us to bring our clients a sophisticated understanding of industry trends, market drivers and regulatory policy.