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21-06001

Public Utilities Commission of Nevada
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Vote Solar



October 6, 2021

SENT VIA PUCN WEB PORTAL AND EMAIL

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East Williams Street
Carson City, NV 89701

Re: Docket Nos. 21-06001 and 21-06002

Dear Ms. Osborne,

Please accept for filing the Direct Testimony and Exhibits of Rao Konidena on Behalf of Vote Solar in the above-referenced dockets. Please do not hesitate to reach out with any questions or concerns. Thank you.

Sincerely,

/s/ Emma Kaboli
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Enclosures
Cc: Service List (via email)

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV)	
Energy and Sierra Pacific Power Company d/b/a/ NV)	
Energy for approval of their 2022-2041 Triennial)	Docket No. 21-06001
Integrated Resource Plan and 2022-2024 Energy Supply)	
Plan.)	
_____)	
)	
Application of Sierra Pacific Power Company d/b/a/ NV)	
Energy for approval of its Natural Gas Conservation and)	Docket No. 21-06002
Energy Efficiency Plan for the period 2022-2024.)	
_____)	

DIRECT TESTIMONY AND EXHIBITS OF RAO KONIDENA

ON BEHALF OF VOTE SOLAR

OCTOBER 6, 2021

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1 **BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

2 Direct Testimony of Rao Konidena

3 On Behalf of Vote Solar

4 Docket No. 21-06001, et al.

5 **I. Introduction**

6 **Q. Please state your name and business address.**

7 A. My name is Rao Konidena. My business address is 2309 Auerbach St, Roseville, Minnesota
8 55113.

9 **Q. On whose behalf are you submitting this direct testimony?**

10 A. I am submitting this testimony on behalf of Vote Solar.

11 **Q. What is Vote Solar?**

12 A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity,
13 promote energy independence, and fight climate change by making solar a mainstream
14 energy resource across the United States. Vote Solar is described further in the testimony of
15 Rick Gilliam also being filed today.

16 **Q. By whom are you employed and in what capacity?**

17 A. I am employed by Rakon Energy LLC, as the Chief Executive Officer.

18 **Q. Please describe your educational background.**

19 A. I received a Bachelor of Engineering (BE) in Electrical & Electronics Engineering from
20 Bangalore University, a Master of Science in Electrical Engineering (MSEE) from the
21 University of Texas at Arlington, and an MBA from the University of Minnesota.

22 **Q. Please describe your experience in utility regulatory matters.**

23 A. I have been an independent consultant for more than three years, working with consumer and
24 environmental advocates, solar developers, and municipal utilities.

25 Prior to my current position, I worked at Midcontinent Independent System Operator
26 ("MISO") from September 2003 through May 2018. I started as an Applications Engineer for

1 Planning, where I ran Loss of Load Expectation (“LOLE”) studies, Capacity Benefit Margin
2 calculations, and load deliverability analysis for the MISO Transmission Expansion Plan
3 (“MTEP”).

4 I was later promoted to Lead, Resource Forecasting, in 2006, and was
5 responsible for a team of engineers running the capacity forecasting software from
6 the Electric Power Research Institute called Electric Generation Expansion Analysis System.
7 That forecasting work was used in the MTEP process. After a
8 promotion to Manager of Resource Forecasting in 2009, I was responsible for
9 leading Demand Response (“DR”) and Energy Efficiency (“EE”) forecasting for MTEP. This
10 was the same time that MISO first started calculating Effective Load Carrying Capability
11 (“ELCC”) for wind resources.

12 I worked in compliance, process, and project management for the entire
13 Transmission Asset Management (“TAM”) division, as Senior Manager, TAM
14 Operations from 2013. In this role, my team and I were responsible for division-
15 wide financial and strategic planning, supporting corporate planning and
16 compliance efforts.

17 I returned to MISO’s Policy Studies department in the Principal Policy Advisor role in
18 2015, leading the long-term load forecasting project and DR, EE, and distributed generation
19 (“DG”) potential study at MISO. Before leaving MISO in 2018, I was responsible for leading
20 policy efforts on energy storage and distributed energy resources (“DERs”). I presented to
21 multiple MISO state commissions, including the Iowa Utilities Board, South Dakota State
22 Public Utilities Commission, and the Organization of MISO States.

23 **Q. Have you previously testified before the Nevada Public Utilities Commission**
24 **(“Commission”)?**

25 **A.** No, I have not.

1 **Q. Have you previously testified before other utility regulatory commissions?**

2 A. Yes. I have testified in proceedings at the Wisconsin Public Service Commission and the
3 Federal Energy Regulatory Commission (“FERC”).

4 **Q. Have you submitted written reports at other utility regulatory commissions?**

5 A. Yes. I submitted written reports representing myself in Integrated Distribution Planning
6 proceedings at the Colorado and Minnesota Public Utilities Commissions. I am also currently
7 writing reports for clients before the Pennsylvania and Minnesota Public Utilities
8 Commissions.

9 **II. Purpose of Testimony and Summary**

10 **Q. What is the purpose of your testimony in this proceeding?**

11 A. The purpose of my testimony is to discuss the flaws in NVE’s Distributed Resources Plan
12 (“DRP”) assessment of NWAs, and how those flaws bias the Companies’ DRP toward
13 traditional wired solutions and against NWAs. The Companies’ DRP is especially biased
14 against distributed solar PV and battery energy storage system (“BESS”) solutions. The
15 Companies’ ultimate decision not to include any NWAs as replacements for planned wired
16 solutions in their 2021 Capital Plan is an erroneous and unreasonable result. I attribute this
17 result to missteps in the DRP process. Of the twenty capital projects in its 2021 Capital Plan
18 for which NVE evaluated NWAs, the Companies either:

19 a) dismissed the NWAs based on cost-effectiveness calculations that relied on faulty or
20 incomplete inputs and erroneous calculations; or

21 b) dismissed the NWAs out of hand for reasons other than cost-effectiveness compared to
22 the wired solution, which appears inconsistent with the applicable statutory and
23 regulatory regimes.

1 As Table 1 shows, below, the Companies identified a total of 20 distribution system
2 constraints for which traditional “wired” solutions were intended. Twelve (12) of those
3 projects are in Sierra Pacific and eight (8) in Nevada Power service territory.¹

4 The Companies’ NWA analyses for nine (9) projects—Imlay (2022), Gypsum (2023),
5 Keehn (2023), Peavine (2023), Incline (2024), Rusty Spike (2025), Keehn Tie (2026), North
6 Red Rock (Cold Springs), and Lemmon Valley (Silver Lake and Stead Substations)—indicate
7 that the NWA is not cost-effective compared to the “wired” project. However, as described
8 below and in the testimony of Vote Solar Rick Gilliam, the Companies’ NWA analyses
9 contain several significant flaws that bias the results towards the “wired” solution, which also
10 corresponds with the utilities’ financial incentives to rate base utility-owned assets. If the
11 NWA analyses were redone with correct inputs and correct procedures, additional cost-
12 effective NWAs are likely. For seven (7) projects—Andrews-Nellis (2022), Northwest
13 (2022), South Meadows (2022 and 2023), Topaz (2022), MYS (2023), and Tomsik (2023)—
14 the NWA projects were cost-effective even with the Companies’ biased NWA analyses, but
15 the Companies propose not to pursue the NWAs at this time for reasons unexplained. Instead,
16 the DRP proposes “further consideration.”² For the remaining four (4) projects, the DRP
17 rejected Beltway (2022) after additional investigation because it found it not to be cost-
18 effective after all, and put off considering Lazy 5 (2025), Bicentennial (2026), and West
19 Tonopah (2026) because the Companies decided in-service date for the wired solution was
20 too far in the future.³

¹ Joint Application to Approve Triennial Integrated Resource Plan, Three Year Action Plan and Energy Supply Plan, Vol. 13, at 94 (Pub. Utils. Comm’n of Nev. June 1, 2021) (hereinafter “Application”). Of these 20 projects, 6 were planned for wired upgrades in 2022, 6 were planned for 2023, 1 is planned for 2024, 2 are planned for 2025, 3 are planned for 2026, and 2 are planned for 2027. *Id.* at 95-100.

² Application, Vol. 13, at 105, 110. The Companies contend that a positive result for cost-effectiveness “does not yet include practical case-by-case considerations such as interconnection/integration costs, potential siting issues/costs, more accurate sizing and costs of the DER technologies in the NWA solutions portfolio, and money that may have already been spent on the traditional wired solution...” *Id.* at 128.

³ *Id.* at 128–129.

Year	Project Name	NVE Found Cost-Effective?	Status?	NVE's Reason for Not Adopting
2022	Imlay	No	Rejected after initial analysis	NVE found not cost-effective
2023	Gypsum	No	Rejected after initial analysis	NVE found not cost-effective
2023	Keehn	No	Rejected after initial analysis	NVE found not cost-effective
2023	Peavine	No	Rejected after initial analysis	NVE found not cost-effective
2024	Incline	No	Rejected after initial analysis	NVE found not cost-effective
2025	Rusty Spike	No	Rejected after initial analysis	NVE found not cost-effective
2026	Keehn Tie	No	Rejected after initial analysis	NVE found not cost-effective
2027	North Red Rock (Cold Springs)	No	Rejected after initial analysis	NVE found not cost-effective
2027	Lemmon Valley (Silver Lake and Stead Substations)	No	Rejected after initial analysis	NVE found not cost-effective
2022	Beltway	Yes, until 2023	Rejected after additional analysis	After additional investigation, found to be more expensive than initially thought (p. 128)
2025	Lazy 5	Yes, until 2027	Delayed consideration, still pursuing wired solution	Companies decided in-service dates were too far out to assess (p. 129)
2026	Bicentennial	Yes, until 2029	Delayed consideration, still pursuing wired solution	Companies decided in-service dates were too far out to assess (p. 129)
2026	West Tonopah	Yes, for all forecasted years	Delayed consideration, still pursuing wired solution	Companies decided in-service dates were too far out to assess (p. 129)
2022	Andrews-Nellis	Yes, until 2027	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear
2022	Northwest	Yes, for all forecasted years	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear
2022	South Meadows	Yes, until 2024	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear
2022	Topaz	Yes, for all forecasted years	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear
2023	MYS	Yes, until 2025	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear
2023	South Meadows	Yes, until 2026	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear
2023	Tomsik	Yes, until 2025	DRP narrative indicates will get "further consideration," but pursuing wired solution	Unclear

Table 1: The Companies' NWA Analysis to Illustrate Wired Solutions Bias

1 That is, the Companies asks the Commission to approve its plan to proceed with traditional
2 “wired” solutions for the following projects, even though the NWA analysis conducted for all
3 projects was biased against NWA and even though even that biased analysis showed the
4 NWA to be more cost-effective on net benefits basis:

- 5 ○ AND1214 – NS1204 Tie, Beltway Bank #3 Addition, Imlay 60/13.2 kV Transformer
6 Upgrade, Northwest 120/25 kV Bank #2 Upgrade, South Meadows 2503 and South
7 Meadows 2506, and Topaz Transformer Addition/Upgrade West Tonopah 2nd Bank
8 Addition projects in 2022;
- 9 ○ Gypsum 69/12 kV Bank 1 Addition, Keehn Bank 3, MYS Bank 1, Peavine Substation,
10 South Meadows Bank 2 and Feeders, and Tomsik 138/12 kV Bank 1 projects in 2023;
- 11 ○ Incline #2 TFMR ADDN project in 2024;
- 12 ○ Lazy 5 120/25 kV Substation and Rusty Spike Bank 2 & 25 kV Feeder projects in 2025;
- 13 ○ Bicentennial Bank 3, KHN1204 to KHN1210 Feeder tie, and West Tonopah 2nd Bank
14 Addition projects in 2026; and
- 15 ○ North Red Rock Sub – 120/25 kV Bus Buildout (aka Cold Springs 120/25 kV Substation)
16 and Lemmon Valley (aka Lemmon Valley 120/25 kV Substation) in 2027.⁴

17 And even though NVE asks for approval for *all* of the originally planned “wired” projects,
18 including Beltway Bank #3, it provides the caveat that Beltway Bank #3 is a possible
19 “exception” to its intent not to “implement any NWA solutions in lieu of a traditional wires
20 solution.”⁵

21 **Q. Please summarize your recommendations.**

22 A. I recommend that the Commission (1) reject the DRP as filed; (2) not approve “wired”
23 projects for which no NWA analysis was conducted, or for which even the Companies’
24 biased NWA analysis shows the NWA to be cost effective; (3) require the Companies to
25 submit new NWA analyses curing the defects in its filed NWA analyses; and (4) condition
26 approval of all “wired” projects on a showing that NWAs are not cost-effective based on a

⁴ *Id.* at 130.

⁵ *Id.*

correctly conducted analysis, and order the Companies to implement all cost-effective NWAs.

Q. Does Vote Solar have any other witnesses in this proceeding?

A. Yes. Mr. Rick Gilliam of Vote Solar is also testifying regarding the screening criteria included in NVE's NWA assessments and the erroneous reliance on utility-scale, utility-owned solar PV and BESS in the DRP.

III. The Companies' NWA Analysis is Insufficient and Flawed.

Q. What is your understanding of the Companies' DRP?

A. The Companies' DRP consists of four main elements, as illustrated in Figure 1 below. These four elements are:

- 1) Hosting Capacity Analysis ("HCA")
- 2) Grid Needs Assessment ("GNA")
- 3) Non-Wires Alternatives ("NWAs") Screening Analysis
- 4) Locational Net Benefits Assessment ("LNBA")

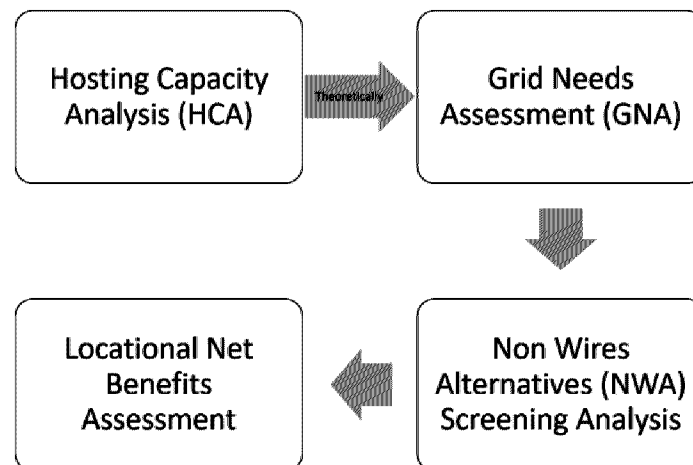


Figure 1: Four Main Elements of the Companies' DRP

Generally speaking, the HCA approximates loading on current distribution system feeders based on a series of data collection, interpolation, and approximations to create representative "profiles" of feeders, which were then used to create a 24-hour load profile on the peak and

1 minimum loading days each month.⁶ In theory, the results can be used to estimate how much
2 Distributed Energy Resource (“DER”) capacity can be added to each feeder without running
3 into reliability issues.⁷ The HCA relied on three simplified scenarios to simulate maximum
4 generation, maximum loading, and a solar-profile informed maximum generation.⁸ It did not
5 rely on actual flows to and from the grid from DERs and customers.

6 The GNA looks at current and future transmission and distribution needs on the system
7 by identifying existing system limitations or “constraints.”⁹ The DRP contains two GNAs
8 based on two different vintages of capital plans (identified constraints and recommended
9 “solutions” based on deployment of traditional “wired” utility infrastructure).¹⁰ The
10 Companies created one GNA from their 2020 Capital Plan (developed in 2019) and one GNA
11 from their 2021 Capital Plan (developed in 2020).¹¹ It appears that the 2021 Capital Plan
12 GNA is based on projects identified as of March 15, 2021.¹²

13 Third, the Companies engage in a screening analysis to develop a “portfolio” of NWAs
14 that could replace or defer the “wired” projects identified.¹³ As a last step, the Companies
15 calculate a “locational net benefits” value through a locational net benefits analysis
16 (“LNBA”) for the portfolio developed in the prior step and then compare the net costs and net
17 benefits of the NWA to the costs of the traditional wired project.

18 A large portion of the DRP consists of descriptions of the projects and the results of the
19 NWA analysis for both the 2020 and 2021 Capital Plans. It is my understanding that the

⁶ Application, Vol. 13, at 36–38.

⁷ *Id.* at 14, 38.

⁸ *Id.*

⁹ *Id.* at 15, 49. While the DRP notes that in the future the HCA may inform the GNA process, it appears not to have done so here. *Id.* at 34 (“Constraints identified on the basis of limited hosting capacity [in the HCA] and the requisite traditional wired solutions to those constraints could feed into the GNA, similar to how traditional thermal, voltage, or reliability constraints are already relied upon.”).

¹⁰ Application, Vol. 13, at 49.

¹¹ *Id.*

¹² *Id.* at 94, n.35.

¹³ *Id.* at 61.

1 2021 Capital Plan¹⁴ is the operative one for purposes of the DRP filing in this case, so I
2 focused primarily on that GNA and set of NWA analyses. More specifically, my testimony
3 focuses primarily on the NWA Screening and the LNBA for distribution projects.

4 Although my primary focus is distribution projects, my general critique of the
5 Companies' use of gross, rather than net, costs to build potential NWA portfolios also applies
6 to its analysis for transmission projects, as does my critique of the Companies' assumptions
7 regarding battery storage. Further, I will note that the Companies mention 3 of 19 projects in
8 the 2021 capital plan for transmission could be replaced or deferred with NWAs, but propose
9 to move forward with wired solutions anyway.¹⁵

10 **Q: What tools do the Companies use to assess the costs and benefits of various NWAs?**

11 **A:** For each proposed capital project, the Companies produced an NWA worksheet that assesses
12 potential costs and benefits of a variety of NWAs (e.g., solar PV, DR, conservation voltage
13 reduction ("CVR"), EE) and assembles a portfolio of those resources that can provide an
14 NWA portfolio solution to the wired project.

15 As I understand the Companies' NWA worksheets, the Companies' input assumed
16 production or performance curve, limitations on, and costs of CVR, EE, DR, and solar PV
17 generation and utilizes a "solver" add-in for Microsoft Excel.¹⁶ The maximum amount of EE
18 and CVR appears to be determinative and critical to all of the analyses. In each NWA
19 portfolio, the Companies' spreadsheet model selects all of the CVR and all or nearly all of the
20 EE made available (2% of loading).¹⁷ No solar is included in any portfolio based on the
21 Companies' claim that "the cost of this technology created a higher NWA portfolio PWRR as

¹⁴ Application, Vol. 13, at 94–130.

¹⁵ *Id.* at 164.

¹⁶ *Id.* at 63, n. 28 (describing the Microsoft Excel spreadsheet tool that performs NWA analysis and LNBA).

¹⁷ *Id.* at 94–130 (narrative descriptions of each NWA portfolio notes that CVR used is "equivalent to the maximum of 2 percent loading reduction each year" and that EE used "up to the maximum of 2 percent loading reduction each year.").

1 compared to portfolios without this technology.”¹⁸ Any remaining overload that remains after
2 CVR, EE, and DR are maxed out (based on the assumed caps) is filled with BESS.¹⁹ Once
3 the “portfolio” is created through those steps, the locational net benefits are calculated by
4 adding the revenue requirements from the NWA “portfolio” and subtracting the avoided
5 energy, capacity and “energy arbitrage” benefits to produce a “net revenue required” value.
6 The present value of net revenue requirements for the life of the NWA investment is added to
7 the revenue requirement impact by deferring the wired solution to compare the total present
8 worth of revenue requirement (“PWRR”) of the wired solution to the PWRR of deferring the
9 wired solution plus the net PWRR of the NWA alternative. A savings presented by the NWA
10 portfolio is considered cost effective.

11 **Q: Do you agree with the values that the Companies used for energy, generation capacity,**
12 **and energy arbitrage benefits for DERs in its NWA Worksheets?**

13 **A:** No. I disagree with the limited categories of values considered, the selective application of
14 those few values to only some NWAs, and with the cost assumptions of some DER
15 technologies. The Companies’ methodology constructs a purportedly “optimized” NWA
16 portfolio based on the DERs gross costs. It only “nets out” the benefits provided by the
17 selected portfolio of NWAs selected in a prior step by subtracting the value of benefits
18 (avoided energy and capacity) from the revenue requirement of obtaining the selected NWA
19 portfolio. That is incorrect and will be addressed more fully by Vote Solar witness Rick
20 Gilliam. Additionally, only energy (either annual avoided energy for solar PV, or energy
21 arbitrage for BESS) and production capacity are “netted” from the NWA costs.²⁰ The
22 Companies’ NWA analysis workpapers contain columns for avoided “RPS/GHG” costs,

¹⁸ *Id.*

¹⁹ *Id.*

²⁰ Application, Vol. 13 at 104.

“Ancillary Value” and “Reduction in Losses,” but I did not see any workpapers in which those columns were populated with values or utilized in calculating net benefits. Nor do the Companies’ LNBA analyses account for other values provided by DERs. Moreover, avoided energy and capacity production cost benefits are not netted from the EE, CVR and DR resources.

Q. What additional values of DERs should be accounted for in the LNBA but were omitted from the Companies’ NWA analyses?

A. The Companies’ NWA analyses only accounted for avoided energy and production capacity, and only for solar PV and BESS. There are a number of additional benefits provided by DERs that were wholly omitted.²¹ To demonstrate, I compare the benefits considered in the Companies’ NWA analysis with the benefits actually provided by NWAs in Table 2, below.

Benefit	Utility System	Society	NVE’s Limited NWA Benefits Considered
Reduced O&M costs	✓	✓	
Reduced generation capacity costs	✓	✓	✓ ("Capacity Value")
Reduced energy costs	✓	✓	✓ ("Annual Energy Benefit + Energy Arbitrage Value")
Reduced T&D costs	✓	✓	
Reduced T&D losses	✓	✓	
Reduced ancillary services costs	✓	✓	
Increased system reliability	✓	✓	
Increased safety	✓	✓	
Increased resilience	✓	✓	
Increased DER integration	✓	✓	
Improved power quality	✓	✓	
Reduced customer outages	✓	✓	
Increased customer satisfaction	✓	✓	
Increased customer flexibility and choice	✓	✓	
Reduced environmental compliance costs	✓	✓	
Other environmental benefits		✓	
Economic development benefits		✓	

Table 2: Additional benefits to be considered in LNBA

²¹ Derived from Tim Woolf et al., *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, Table 2 - Examples of Benefits for Utility-Facing Grid Modernization (Feb. 2021), <https://www.synapse-energy.com/sites/default/files/GMLC-Grid-Mod-BCA-2021-02-02-18-094.pdf>.

Moreover, it does not appear that the LNBA analysis even considers the avoided energy and production capacity benefits of EE, CVR or DR. The spreadsheets the Companies use to calculate the LNBA for NWA portfolios appear to omit any energy or capacity values from those resources.

Q. What, if anything, does the DRP say about the additional benefits from DERs?

A. The DRP contends that it will consider avoided RPS costs, T&D Losses, Greenhouse gas emissions, and Reliability/Power Quality in the future.²² However, by identifying these benefits but postponing assigning any values to them, the Companies effectively assume the avoided energy and capacity from EE, DR, and CVR and the avoided RPS costs, avoided greenhouse gas costs, avoided T&D losses, reliability and power quality benefits from all DERs are zero. That dramatically overstates the “net” cost of those resources for purposes of the cost-effectiveness comparison. Just because the Companies have not quantified these benefits does not mean they have no value.

Moreover, the energy arbitrage values included in the LNBA calculations utilize the difference between peak and off-peak prices assuming a 25 MW four-hour battery for all needs on the system. However, that is overly simplistic and ignores the additional benefits provided by a BESS’s ability to dispatch over shorter periods than an hour. The Companies should quantify the energy arbitrage benefits of BESS on a sub-hourly, not just hourly, basis.

Q: Please summarize the problems with the Companies’ LNBA calculations.

A. The Companies’ LNBA calculations contain several errors that understate the benefits from NWAs, prejudicing the NWA when compared to the traditional “wired” solution. Those errors included:

²² Application, Vol. 13, at 129.

- Creating a “portfolio” of NWAs based on those resources’ gross costs, rather than costs net of benefits, and only calculating the net benefit for the portfolio ultimately selected. This fails to select optimized NWA portfolios that include DERs, like solar PV, that have comparably higher gross costs but overall better net benefits.
- Only considering the avoided energy and production capacity benefits of solar PV and BESS, rather than the approximately 16 additional values identified in value of solar analyses done elsewhere.
- Not considering avoided energy or capacity values from EE, DR, or CVR.

Q. What impact would correcting for these errors have on the results of the NWA analyses?

A. Correcting each of these errors would increase the cost-effectiveness of NWAs compared to traditional “wired” projects. Correcting all of them would significantly improve the savings available by utilizing NWAs compared to traditional “wired” investments.

IV. The Companies’ Analysis Miscalculates the Costs and Benefits for Battery Storage

Q: Do you have any other concerns with the Companies’ cost and benefit values for battery storage?

A: Yes. I have three additional concerns. First, the Companies used a production cost simulation software called PROMOD to quantify the avoided energy and energy arbitrage benefits of BESS, but PROMOD has significant limitations when used to model BESS.²³ Second, the Companies are not using up-to-date energy storage cost data. Third, the Companies only modeled 25 cycles per year, rather than the full 10,000 cycles, or a 10-year warranty, which would be more appropriate.

²³ *Id.* at 89 (“Avoided Energy – The value of avoided energy based upon hourly energy prices as estimated by production cost simulation software (“PROMOD”).” and “Energy Arbitrage – The value of charging a 25 MW four-hour battery during off-peak hours and discharging it during on-peak hours as estimated by PROMOD.”).

1 **Q: Why are you concerned about the use of PROMOD to model battery storage?**

2 **A:** PROMOD is insufficient to model BESS benefits for two reasons. First, PROMOD is an
3 hourly production cost modeling tool, not a sub-hourly tool. As a result, the Company does
4 not identify the additional benefits available from BESS for durations less than an hour.
5 Second, PROMOD is outdated and does not have a function for BESS simulations. Instead,
6 PROMOD models battery storage as pumped hydro storage. As a result, the Company misses
7 the full suite of benefits that battery storage provides when responding to a system need.

8 **Q: Please explain why modeling at a sub-hourly increments is important for calculating the**
9 **energy benefits of a NWA.**

10 **A:** As DRP Table 27 shows, deficiency start and end times do not always start or stop at the
11 beginning or end of the hour, and deficiencies vary in duration.²⁴ Therefore, using PROMOD
12 fails to meet the timeframe of the deficiencies.

13 **Q: Please explain why PROMOD’s pumped storage modeling does not capture battery**
14 **storage benefits.**

15 **A:** There are several reasons why a pumped storage model is not an appropriate method for
16 assessing battery storage. First, PROMOD is locking in thermal generation dispatch before
17 dispatching storage because the type of pumped storage it is designed to model requires that
18 generation.²⁵ So, the NWA battery in the PROMOD model is only dispatched after thermal
19 generation is dispatched when there is a need on the system, which is not an accurate model
20 of BESS operations. Second, the storage schedule is “locked-in,” which is not how batteries

²⁴ *Id.* 101–103, DRP Table 27.

²⁵ ABB, “Hydro and Pump Storage Modelling in ABB Ability™ PROMOD®: Benchmark Report,” at 3, https://library.e.abb.com/public/2bb611278afe4d8bac8555addc262bfb/Hydro-Pump-Storage-Modeling-PROMOD_9AKK107046A5365-A4.pdf (“A pump storage unit consumes power to pump water into a reservoir during off-peak hours and generates during on-peak hours based on the price signals. PROMOD provides flexibility to dispatch these storage units against the locational marginal price (LMP). This dispatch takes place after the preliminary dispatch of the thermal units in the system (end of the first iteration).”).

operate.²⁶ Unlike pumped hydro storage, a battery can respond in minutes—and sometimes in seconds—to system needs such as frequency regulation.²⁷ By locking in a schedule based on the operations of a fundamentally different technology, PROMOD is not able to realize the full benefits of BESS as an NWA.

Q: Why are you concerned that the Companies are using out-of-date cost and benefit data regarding energy storage systems?

A: The DRP lists costs for BESS of \$341,000/MWh or \$1,365,000/MW in its NWA analysis methods for the 2021 Capital Plan.²⁸ This assumed capital cost is high, in my opinion. Energy storage costs must be compared to other utilities that implemented storage recently, rather than using the high capital costs that the Companies' model assumes. Additionally, it appears that the Companies assume a low number of cycles for battery storage. The Companies model energy storage costs at 25 cycles per year instead of the standard practice of 10,000 cycles or a 10-year warranty.²⁹ In my professional experience with storage vendors and manufacturers, it is common for warranties to be based on a 10-year/10,000 cycle period to provide the operator with flexibility to cycle the battery more than once per day. More cycles generally translates to lower costs. because a higher cycle assumption makes more room to avoid battery degradation. It is unclear the extent to which this impacts the BESS

²⁶ *Id.* at 4 (“This schedule is essentially ‘locked in’ and treated as a modification to the load for the thermal dispatch of all remaining units and subsequent transactions.”).

²⁷ Nat'l Renewable Energy Lab., “Grid-Scale Battery Storage: Frequently Asked Questions,” at 2–3, <https://www.nrel.gov/docs/fy19osti/74426.pdf> (“BESS can rapidly charge or discharge in a fraction of a second, faster than conventional thermal plants, making them a suitable resource for short-term reliability services, such as Primary Frequency Response (PFR) and Regulation.”).

²⁸ Application, Vol. 13 at 104.

²⁹ *See, e.g.,* Sonnen, “Tech Specs – sonnen eco Gen 31,” <https://cdn-sonnen-media.s3.amazonaws.com/0024e065-f9f6-4c5d-bd80-b654ff2567cf-en-download> (offering 10 year/10,000 cycle warranty); Tesla, “Powerwall Data Sheet,” https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%20AC_Datasheet_en_northamerica.pdf (offering the same); LG CHEM Warranty, https://www.lg.com/us/business/download/resources/BT00002151/180830_LG_ESS_Datasheet.pdf (offering the same).

assumptions in the NWA analyses. The Companies should redo the analyses with more representative cycling.

V. The Companies' Analysis Misvalues the Costs of Solar PV and Mistakenly Considers Utility-Scale Solar Rather than Distributed Solar.

Q: What concerns do you have with the costs for solar PV in the Companies' NWA Worksheets?

A: While I am not a lawyer, the assumption of utility-scale and utility-owned solar for the DRP's NWA analysis does not conform to my read of the statutory and regulatory requirements of the DRP, as Mr. Gilliam discusses in depth in his testimony. The Companies should be using distributed scale solar cost estimates in the NWA template because they should be comparing distribution-level technologies, not utility-scale, transmission-level technologies, and the cost estimates that the Companies use based on utility-scale solar are not accurate for distributed solar.

Q: What happens with more utility-scale solar penetration on the transmission grid?

A: Similar to wind, another renewable energy source, when we add more utility-scale solar to the transmission grid, the capacity contribution of solar declines over time.

Q: What is capacity credit and why is it relevant for the Company's utility-scale solar capacity assumption?

A: Capacity credit is how much of the variable solar generation should be counted towards planning reserve margin requirement that is the result of a LOLE reliability analysis. For example, in a 100 MW solar unit, if the capacity credit is 50%, only 50 MW is counted towards meeting resource adequacy requirements.

Q: How is capacity credit for solar determined?

A: In general, an Effective Load Carrying Capability ("ELCC") calculation is run, with and without solar for different solar penetration scenarios against an annual load shape. In the

figure below, as an example from California electric utilities, the ELCC MW is the difference between the adjusted net load shape and the load shape that includes solar.³⁰ The adjusted net load shape is the load shape when load is added to the system to meet the 1 day in 10-year LOLE criteria.

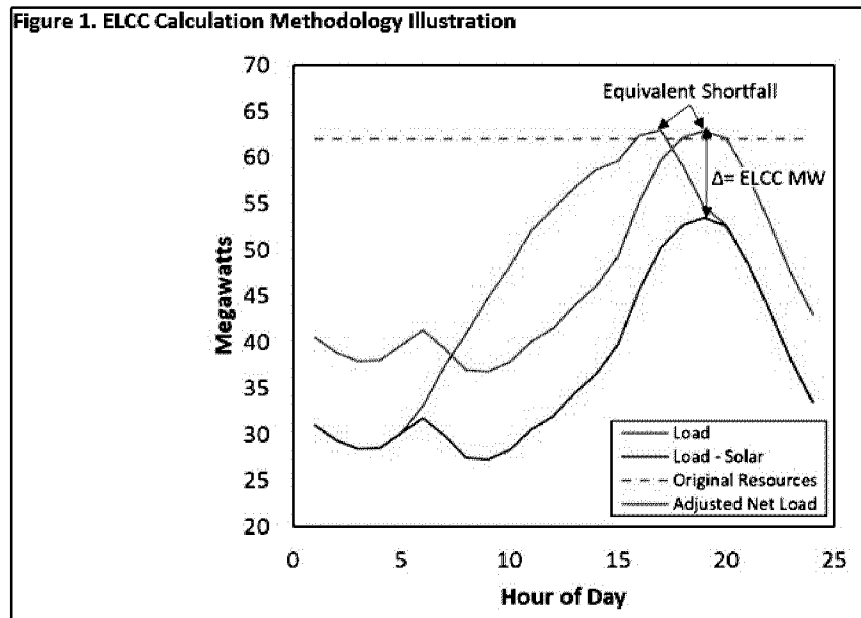


Figure 2: ELCC Calculation Method for solar capacity credit

Q: What happens when a large amount of solar is added to the electric grid?

A: The capacity credit falls when large amounts of solar energy are added to the grid.³¹ Hence, the Companies should not assume a constant capacity credit for solar to count towards meeting its resource adequacy obligations. However, unlike utility-scale solar lumped together at a particular location, distributed solar is spread out at various locations, thereby reducing the instances when ELCC reduces. Modeling ELCC for distributed solar would

³⁰ Cal. Pub. Util. Comm'n, *Status of Advice Letter 5868E*, at PDF 19, https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5868-E.pdf (ELCC Study from California's large investor-owned utilities).

³¹ Astrapé Consulting, *2021 Joint CA IOU ELCC Study*, at 8 (June 22, 2021), <https://www.astrape.com/publications/> ("It is well understood that as solar penetration increases, net load shifts to later in the day, reducing the ELCC for marginal solar resources").

1 ensure an accurate treatment of solar in the NWA Screening Analysis. The load shapes at
2 various locations are different, and since ELCC would be run with and without distributed
3 solar against the load shape, ELCC for distributed scale solar is more appropriate for the
4 NWA analysis.

5 **Q: Does the Company model ELCC for both utility-scale and distributed-scale solar?**

6 **A:** No, the Companies did not model ELCC for distributed-scale solar. The Companies mention
7 ELCC analysis for utility-scale solar in Company Witness Hart's testimony.³² Additionally,
8 the Companies address the reduction in ELCC for higher penetrations of utility-scale solar in
9 Company Witness Williams's testimony.³³ But there is no mention of ELCC for distributed
10 solar NWA in either of those testimonies.

11 **Q: Are there specific instances where the Companies can quantify the benefit of distributed**
12 **solar ELCC?**

13 **A:** Yes, the Companies can model ELCC for distributed solar at each of the substation facilities
14 identified in DRP Table 27.³⁴

15 **Q: Can you summarize your concerns with the Companies' treatment of utility-scale solar?**

16 **A:** The Companies are assuming lower capital costs for utility-scale solar because they are
17 missing transmission interconnection costs. Additionally, even though the Companies realize
18 ELCC declines over time, leading to reduced capacity contributions from utility-scale solar,
19 the Companies did not model NWA distributed solar ELCC.

³² Application, Vol. 3, A. Hart Dir. Testimony, at 20:1–6 (“Their Effective Load Carrying Capabilities (“ELCCs”) vary inversely with the amount of intermittent renewable penetration on the system. That is, as the total aggregate amount of nameplate intermittent renewable capacity increases, the ELCC as a percent of nameplate capacity decreases.”).

³³ Application, Vol. 3, K. Williams Dir. Testimony at 14:22–23 (“The ELCC of solar PV and storage declines at higher penetration levels.”).

³⁴ Application, Vol. 13, at 101–103, DRP Table 27.

1 **VI. The Companies' Analysis Misvalues Demand Response Resources.**

2 **Q: What concerns do you have with the Company's DR modeling?**

3 **A:** The Companies include no DR in the NWA evaluation for some feeders: Antelope Valley
4 substation,³⁵ Dutch Flat substation,³⁶ Incline Transformer #1,³⁷ Reese River Transformer
5 #1,³⁸ and Gypsum Transformer #2.³⁹ This is the case even though the Companies have a total
6 of 11.2 MW of DR programs.

7 The Companies state that DR capacity is absent for the above feeders. Specifically, the
8 Companies omitted DR from feeders which currently do not host customers participating in
9 DR.⁴⁰ It is not clear, however, that customers cannot be recruited or programs cannot be
10 improved to encourage participation on those feeders. I also note that, contrary to the
11 Companies' claim that no current DR is located on the Incline substation, it appears that the
12 substation hosts 107 kW of existing DR. It is not clear if this is an oversight.

13 **Q: Why is DR modeling crucial to the NWA evaluation?**

14 **A:** Residential DR programs can clip distribution system peak demand. NWAs are feasible
15 solutions where they deliver demand reductions at the time of system constraints, which is
16 known as their "coincidence factor." Coincidence factors show how much percentage of time
17 a particular technology can meet the peak demand. For example, Figure 2 below from ConEd
18 shows a coincidence factor of 0% at most hours but 91% at hour 18.⁴¹ For DR-Residential
19 program, the coincidence factor is mostly 0% because the participants are not required to

³⁵ *Id.* at 68.

³⁶ *Id.* at 74.

³⁷ *Id.* at 75.

³⁸ Application, Vol. 13 at 78.

³⁹ *Id.* at 79.

⁴⁰ *See id.* ("DR was not included in the NWA solution portfolio because of an absence of DR capacity on the feeders served by the substation, and the cost associated with achieving incremental DR capacity did not result in a minimized NWA PWRR for all the years studied.").

⁴¹ Con Edison of New York - Benefit Cost Analysis (BCA) Handbook, <https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/coned-bcah.pdf?la=en>

reduce their demand during off-peak hours. This chart shows how residential DR can be effective during the peak hour 18, when solar PV production is ramping down.

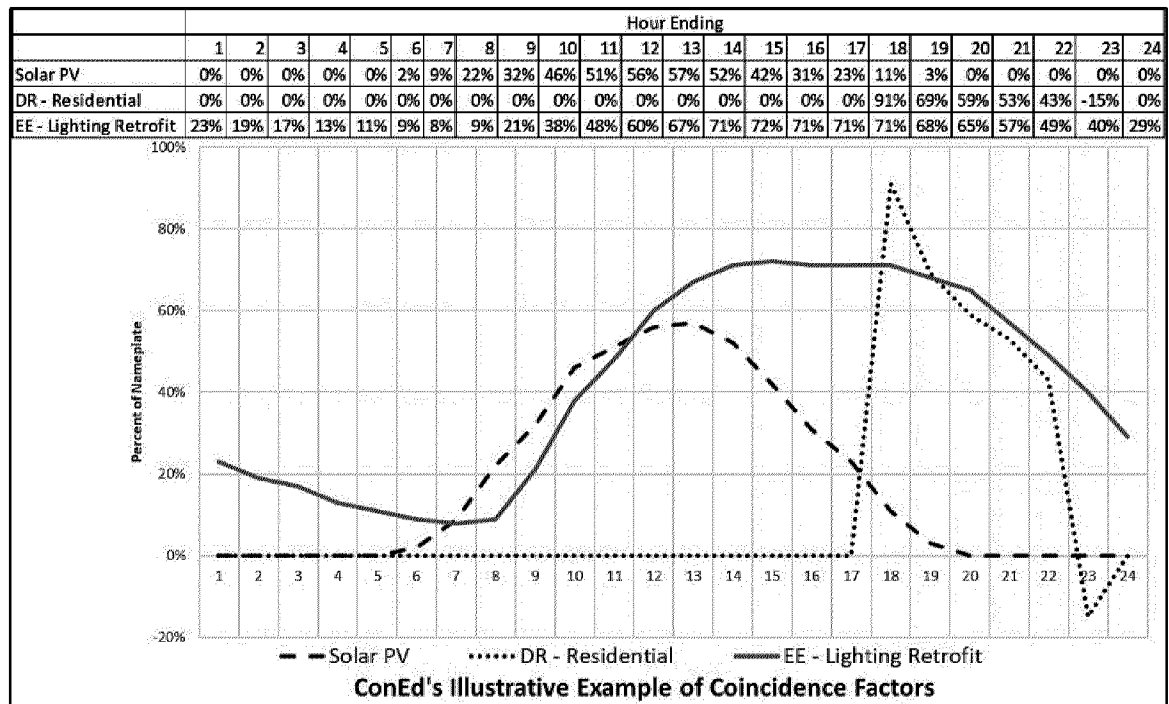


Figure 3: ConEd's Coincidence Factors Example to illustrate the impact of Demand Response on NWA

Q: Why are coincidence factors crucial in the NWA Portfolio evaluation?

A: The Companies point out that the services from NWAs do not always align with the needs on the distribution system.⁴² But by considering coincidence factors for each of the alternatives considered in the NWA, the Companies could transparently evaluate when those needs are aligned with NWA solutions. Without including this type of analysis, the NWA assessment is incomplete.

⁴² Application, Vol. 13, at 61 (“DERs have the potential for deferring, and in unique cases eliminating, the need for traditional infrastructure solutions. However, the services that they provide do not always align with the needs or characteristics of existing or forecasted constraints on the utility electric system.”).

1 **Q: Can energy storage be used as a DR solution?**

2 **A:** Yes, utilities are increasingly incorporating energy storage as a DR solution to reduce
3 renewable energy curtailment.⁴³

4 **Q: How is energy storage as a DR solution different from energy storage as a NWA?**

5 **A:** As a DR solution, energy storage reduces demand when charging from the distribution grid.
6 The battery is clipping the peak demand when charging. That same charging can occur when
7 there is excess renewable energy. Otherwise, curtailment of excess renewable energy occurs.
8 And that is the benefit for the Companies when energy storage is deployed as a DR solution.
9 However, as an NWA, energy storage is limited in its application by the Companies.

10 **Q: Can you summarize your concerns with the Companies' treatment of DR?**

11 **A:** First, the Companies omitted DR from feeders that do not currently host DR, but current
12 participation is not a prerequisite to future DR participation. As mentioned above, DR
13 programs have short lead times similar to energy storage⁴⁴. Hence, the Companies must more
14 diligently evaluate demand response as a viable NWA, including evaluating energy storage as
15 a demand response solution.⁴⁵

⁴³ Smart Electric Power Alliance, *2019 Utility Demand Response Market Snapshot*, at Slide 36, <https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/> (“As the energy storage market expands, it will play a growing role in demand management and renewable energy integration. Utilities are recognizing the value that aggregated energy storage can offer in DR efforts, by reducing renewable energy curtailment, leading to increased renewable energy penetration.”).

⁴⁴ See generally Energy Information Administration, *Cost and Performance Characteristics of New Central Station Electricity Generating Technologies*, at 2, Table 1 (Feb. 2021), https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf. Although DR programs are not called out specifically in this Energy Information Administration document, most industry stakeholders agree that lead times for DR programs are close to a year or less.

⁴⁵ Application, Vol. 13 at 180 (“NV Energy is working to include energy storage systems as a DR asset in the residential sector.”).

VII. The Companies' Rejection of NWAs Based on Lead Time Conflicts with its Mandate to Consider a Six-Year Period in its DRP.

Q: What is your concern with the Companies' rejection of NWAs based on lead time?

A: The Companies artificially narrow the window of grid investments analyzed for potential NWAs in conflict with the directive of NAC 704.9237(2)(f) for a DRP to cover a period of “not less than 6 years, beginning with the year after the distributed resources plan is filed.”⁴⁶ The Companies start with a six year window, but then refuse to pursue solutions with shorter lead times and put off considering solutions for needs further out in that window.^{47, 48} Those limitations imposed on the front and back of the six year window narrow the window in which the Companies are actually considering implementing NWAs, despite a clear regulatory mandate to assess them for “not less than 6 years.” As a result, the Companies ignore potentially highly beneficial NWAs because the transition from a wired solution would be either too near or too far temporally, while continuing forward with plans for wired solutions as usual. In the case of the Lazy 5 substation, the Companies even admitted that “the results in DRP-Table 41 for the NWA analysis associated with the Lazy 5 substation appear quite favorable towards an NWA portfolio solution being more cost-effect [sic] than the planned wired capital upgrade project solution,” yet the Companies still refuse to take any steps to implement the cost-effective NWA on the basis of additional considerations that they

⁴⁶ NAC § 704.9237(2)(f).

⁴⁷ Exh. RK-3, NVE Response to Data Request NCARE 2-05 (“[T]he Companies do not consider projects with planned in-service dates within approximately 12 to 18 months from the time that the NWA analysis is being performed.”).

⁴⁸ See Application, Vol. 13, at 105–120 (stating for eight different projects that the Companies considered NWA portfolio solutions sized to defer the wired project for two or three years, “but not sized large enough to address the forecasted overload beyond that.”). See also Application, Vol. 13, at 129 (explaining that the Companies chose not to move forward with NWA solutions at the Lazy 5, Bicentennial Bank 3, and West Tonopah 2nd Bank Addition projects in 2026 because the in-service dates for their potential wired solutions were “several years in the future,” and stating it would consider whether to “continue with the wired traditional capital upgrade projects or transition to NWA DER portfolio solutions at the appropriate time closer to the in-service dates for the projects.”).

1 left out of the DRP (for reasons unexplained) and vague assertions regarding the timing and
2 scale of the NWA.⁴⁹

3 By refusing to consider NWAs with short lead teams, the Companies fail to recognize
4 that distributed resources often inherently have shorter lead times—months rather than
5 years—and unnecessarily prejudice the analysis against adoption of NWAs by using the time
6 frames of wired solutions as a parameter. This issue is also at high risk for repetition in every
7 subsequent DRP, because a project whose lead time is too long or whose in-service date is
8 too far out could then be too near-term by the time of the next DRP filing. This heavily
9 subjective reliance on the Companies' own lead time assessments means that the Company
10 can essentially use lead time as an excuse not to pursue any NWA that it wants regardless of
11 whether that NWA is more cost-effective than the wired solution it would replace or defer.

12 **Q: What are the specific instances in this DRP where the NWA Screening Analysis does not**
13 **make intuitive sense due to the Companies' focus on lead times?**

14 **A:** As shown in the table below, due to the focus on lead times, the Companies are pursuing
15 wired alternatives for at least 5 instances out of the possible candidates in DRP Table 27
16 where there are clear positive net savings with NWAs.⁵⁰

⁴⁹ Exh. RK-3, NVE Response to Data Request NCARE 2-05.

⁵⁰ Application, Vol. 13, at 101–103, DRP Table 27; *compare to* “Net (Wired-NWA) = Savings” Columns in DRP Table 28 (AND1214 – NS1204 TIE) (p. 105), DRP Table 29 (Beltway Bank #3 Addition) (p. 106), DRP Table 31 (Northwest Bank #2 Upgrade) (p. 108), DRP Table 33 (Topaz Transformer Addition) (p. 110), DRP Table 38 (South Meadows Bank 2 and Feeders) (p. 115).

Year	Substation	Estimated Cost	Net Savings	Result
2022	Nellis	\$3,696,995	\$519,014	Savings Positive
2022	Beltway	\$2,881,606	\$321,722	Savings Positive
2022	Topaz	\$4,149,314	\$334,207	Savings Positive
2023	Mira Loma Transformer (South Meadows Project)	\$5,974,234	\$1,027,748	Savings Positive
2023	Northwest	\$4,464,858	\$670,811	Savings Positive

Table 3: DRP Table 27 with NWA Net Savings

Q: What additional conclusions do you draw from comparing DRP Table 27 with the Net Savings Calculated in the NWA spreadsheets?

A: Some of the estimated costs are relatively high in millions of dollars for the wired solutions at substations such as Nellis, Beltway, Northwest, Topaz and the Mira Loma Transformer at South Meadows, compared to their respective Net Savings.⁵¹ These five projects warrant additional consideration by the Companies because NWAs would be cost-effective compared to the wired solutions.

VIII. Conclusion and Recommendations

Q: What are your recommendations to the Commission?

A: I recommend that the Commission reject the Companies' DRP as filed, and require the Companies to complete a new analysis of NWAs for the sites in its 2021 Capital Plan that incorporates accurate costs and benefits and does not screen beneficial NWAs based solely on their lead time.

Q: Does this conclude your testimony?

A: Yes, it does.

⁵¹ *Id.*

Exhibit RK-1

Affirmation

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, I, Rao Konidena, swear that I am the person identified in the attached Direct Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

Executed on: October 6, 2021

KV Nagaraj Rao
Rao Konidena

Exhibit RK-2
Statement of Qualifications

RAO KONIDENA

ENERGY MARKET EXPERTISE IN DISTRIBUTED ENERGY RESOURCES

Roseville, MN 55113 Cell: 612-594-9257 · rkonidena76@gmail.com

Rao Konidena found Rakon Energy LLC because Rao is passionate about connecting clients to cost-effective solutions in energy consulting, storage, distributed energy resources, and electricity policy. Rao likes helping clients with his expertise in electricity policymaking and U.S. energy markets.

Rao was recent with Midcontinent ISO (MISO) as Principal Advisor for Policy Studies, working on energy storage and distributed energy resources. At MISO, Rao worked in management and non-management roles around resource adequacy, economic planning, business management, and policy functions.

Rao is Co-President of the Finnish American Chamber of Commerce – Minnesota (FACC-MN), and on the Board of Ever Green Energy and Minnesota Solar Energy Industries Association (MnSEIA).

EXPERIENCE

RAKON ENERGY LLC, Roseville, MN
President & Chief Executive Officer (CEO)

May 2018 – Present

Providing consulting services related to Federal and state energy policies focusing on energy storage and distributed energy resources

- An aggregator engaged Rakon Energy as part of the team to represent their interests at RTO stakeholder committees on FERC Order 2222.
- Rakon Energy is part of the team engaged by a technology company to represent their interests at the PJM RTO.
- Advanced Energy Economy and the Natural Resource Defense Council's Sustainable FERC Project engaged Rakon to monitor and advocate for the FERC Order 2222 implementation process in MISO.
- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to support OCA's response to the questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets.
- A prominent solar advocacy group currently engaged Rao for expert testimony work in a Minnesota IOUs IRP filing.
- He submitted comments to Minnesota and Colorado Public Utilities Commission on Integrated Distribution Planning dockets.
- He has provided expert testimony support for Environmental Law and Policy Center (ELPC) at the Public Service Commission of Wisconsin (PSCW) on the MISO Multi-Value Project (MVP) line in Wisconsin.
- Provided affidavit support for Office of the People's Counsel of District of Columbia (OPC-DC) at Federal Energy Regulatory Commission (FERC) on PJM's Reserves Pricing Proposal, and municipal utilities in Wisconsin and Missouri at FERC on MISO's Resource Adequacy construct.
- Provided advocacy support for Energy Storage Association (ESA) at MISO on FERC Order 841 Compliance, presented multiple times at MISO Market SubCommittee (MSC)
- Provided training as part of the Tuatara team on DERs to Colombia's grid operator XM, and as part of the ESTA International team on energy storage benefits to Mexican regulator CRE. This training presentation grew out of designing a day and a half course on each Energy Storage value metric.

Advisor, Volunteer, Pro-Bono assignments

- Rao presented on Distributed Energy Resources (DER) and peer-reviewed Demand Side Management and DER plans for Central American regulators, as part of NARUC International Peer Review.
- Rao presented and shared best practices around the impact of provisioning ancillary services. At an Eastern Africa regional workshop organized by the United States Energy Agency (USEA), the United States Agency for International Development (USAID) and the Power Africa initiative.

<https://rakonenergy.com/>

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO), Eagan, MN
Principal Advisor, Policy Studies

Aug 2015 – May 2018

- Recognized as an expert on all thing's energy storage and distributed energy resources from an economic transmission planning perspective
 - Established a business case for ISO visibility into T&D interface via increased planning models' granularity such as sector-oriented load shapes, surveying which transmission buses can handle increased penetrations of DERs and storage, and netload forecasts
 - Built credible relationships with Organization of MISO States (OMS) on DERs, and presented on Energy Storage efforts at Iowa and South Dakota state commissions
 - Project manager for leading studies oriented towards increased penetrations of E.V.s and energy storage
 - Wrote a paper on Distribution System Operator (DSO) framework for an internal audience
 - Working with Professors at Univ of Minnesota and Univ of St Thomas on micro-grid related research efforts
- Project manager for long term independent load forecast and demand response/energy efficiency/distributed generation potential study.
- MISO representative on Department of Energy (DOE) US DRIVE Grid Interaction Technical Team

Senior Manager, Transmission Asset Management Operations

Feb 2013 – July 2015

- He engaged the division lead in the development of strategic initiatives and operating plans.
- Rao chaired the Economic Modeling Framework Working Group of international Grid operators GO-15.

Manager, Resource Forecasting (started at Engineer II)

Sep 2003 – Jan 2013

- **Main Accomplishments**
 - In this role, I directed the Demand Response & Energy Efficiency potential study for MISO, with the support of Global Energy Partners consultants.
 - Directed the MISO Energy Storage Study identifying the economic potential for grid-scale energy storage in MISO footprint, providing strategic consulting services to investor-owned utilities, public power utilities, asset owners, and investors.
- **Regulatory Experience**
 - Responsible for analytical assessments that meet MISO's Federal Energy regulatory compliance obligations as well as our Transmission Owners (e.g., FERC Market-based rates).
 - Responsible for supporting state regulators and MISO Board of Directors with technical analysis related to policy drivers.

PWRSOLUTIONS, Inc., Dallas, TX (Consulting)

May 2001 – August 2003

Student Intern and Electrical Engineer

- Rao executed generator interconnection studies for Independent Power Producers (IPPs) clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

EDUCATION

THE UNIVERSITY OF MINNESOTA, Minneapolis, Minnesota
Carlson School of Management
Master of Business Administration, Global Executive Program
Emphases: Strategic Management, International Business

May 2011

- Responsible for all financial aspects of Virtual Team Project (interfacing with colleagues from China, Poland, and Vienna programs) marketing mobile charging services for Electric vehicles in the Singapore market.
- I built upon my analytical engineering training with rigorous Executive level course work, managing a full-time job at the same time.

UNIVERSITY OF TEXAS AT ARLINGTON, Arlington, Texas
Energy Systems Research Center (ESRC)
Master of Science in **Electrical Engineering**

May 2002

- Master's Thesis in Economic Analysis of Distributed Generation (Photovoltaics (P.V.) and Fuel Cells)

BLOG POSTING, PUBLICATIONS & PRESENTATIONS

1. Energy Storage can increase the life of conventional units, Network Resource Interconnection Service is a better choice than ERIIS for small-scale renewable developers, and Renewable hydrogen is here to stay - Published in Renewable Energy World, August 2020.
2. A suggested approach to site storage resources in transmission planning models, accepted at **MRS Energy & Sustainability**.
3. Solar prospects rise in MISO utility resource plans, It is time to allow third-party aggregators in the MISO States, Hope for favorable hybrid interconnection rules with FERC technical conference, Published in Renewable Energy World, July 2020.
4. Why competitive transmission should extend to low-voltage projects, Hope for storage developers as the first interregional transmission project approaches approval, The good, bad and ugly for understanding the value of DER, Published in Renewable Energy World, June 2020.
5. The Pathway to 100% Renewable must include changes in regulation, focus on operations and promotion of innovation, accepted for publication at **MRS Energy & Sustainability**
6. How to treat Energy Storage as a Transmission Asset, accepted at **MRS Energy & Sustainability**.
7. Why Michigan's capacity prices offer hope for renewable projects in MISO, Published in Renewable Energy World, May 2020.
8. States and Utilities should not have the opt-out of FERC Order 841, Published in CleanTech Law Partners, May 2020.
9. A Proposal for Compensating Reactive Support and Voltage Control in MISO Market, accepted for publication in **Electricity Journal**, July 2020
10. Why should FERC act on Distributed Energy Resource Aggregation (DERA) now?, Published in Renewable Energy World, May 2020.
11. Three steps to take for a VDER to participate in NYISO's capacity and ancillary services market, Energy Storage is the key to energy access in East Africa, Published in Renewable Energy World, April 2020.
12. Energy Storage at Water Pumping Stations for backup power, to be published in Waste Water Digest, April 2020.
13. Three reasons why dual participation market model at NYISO is best for energy storage, Three reasons why MISO should prioritize hybrid interconnections, Published in Renewable Energy World, March 2020.
14. Best Practices from International experiences for Eastern Africa countries regarding Ancillary Services markets, accepted at **Electricity Journal**, August 2020.
15. Why is ERCOT a ripe market for hybrid energy storage? Published in Renewable Energy World, March 2020.
16. A constructive critique of Minnesota's Energy Storage Study: The Study may underestimate the overall value of energy storage in Minnesota, soon to be published, 2020.
17. Submitted comments at Minnesota Public Utilities Commission (PUC) on MN utilities 2019 Integrated Distribution Plans.
18. **Law360** article published in January 2020, "Energy Storage As A Transmission Asset In Regional Markets."
19. **IEEE SmartGrid Newsletter**, February 2020, "Renewables provide a pathway for clean transportation."
20. **Electricity Journal** published in March 2020, "Microgrids and their reliance on Transmission and Distribution network."
21. Published in May 2019 in **Cambridge Press**, "FERC Order 841 levels the playing field for energy storage."
22. Published on LinkedIn, "Federal Power Act section 206 and grid resiliency ", "Participating in a Board is essential for professionals," "An article on why grid-scale storage penetration will increase," "Distributed Energy Resources Aggregation Opportunities in FERC jurisdictional ISOs," and "Make way for ducklings, i.e., distributed energy resources." Not all articles are listed here.
23. Konidena, R. (with Bixuan Sun and Derya Eryilmaz). Transparency in long-Term Electric Demand Forecast: A Perspective on Regional Load Forecasting. **IEEE SmartGrid Newsletter**, August 2019.
24. Published in 2016 International Conference on Global Energy Interconnection, "Declining cost data for emerging technologies in ISO footprint, and their impacts," with Dr. Wei-Jen Lee, Dr. Zhaohao Ding,

and Ann Benson.

25. Visiting Professor, Lectures on U.S. Electricity Markets, North China Electric Power University (NCEPU), Beijing, China. June 2015
26. Published Energy Storage Working Group # 7 report for Grid Operators, Dec 2012
27. Published in IEEE, “Assessment of Grid-Scale Energy Storage Potential Within the MISO Footprint,” with MISO colleagues, July 2012.
28. Published in IEEE, “Integrating Demand Response and Energy Efficiency Resources into MISO’s Value-Based Transmission Planning Process,” with MISO colleagues, July 2012.
29. I presented on Minnesota electricity markets at Arctic Energy Summit, Helsinki, Finland – September 2017, on behalf of the Finnish American Chamber of Commerce- M.N.
30. I presented at Danish Technical University (DTU) upon invitation, Copenhagen, Denmark. May 2017. The topic was Electricity Markets.
31. I presented at International Energy Agency (IEA) Hybrid & Electric Vehicle Technology Collaboration Programme Task 28 “Home Grids and V2X Technologies” workshop, Paris, France, October 2016. The topic was the Electric Vehicle penetration potential at MISO.
32. Presented on Energy Storage in U.S. Electricity Markets at Asia Clean Energy Forum - Manila, Philippines as part of USAID, June 2016.

BOARD & VOLUNTEER ACTIVITIES

- Board of Directors, Ever Green Energy. Sep 2019 – present
- Board of Directors, Minnesota Solar Energy Industries Association. Sep 2020 - present
- Co-President, Finnish American Chamber of Commerce – Minnesota (FACC-MN). Jan 2016 - present

Exhibit RK-3

NVE Response to Data Request NCARE 2-05

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	21-06001	REQUEST DATE:	08-02-2021
REQUEST NO:	NCARE 2-05	KEYWORD:	Vol. 13, Narrative, Distributed Resource Plan DRP-Table 24 (130-132 of 311); NWA
REQUESTER:	Cameron Dyer	RESPONDER:	Sinobio, Joseph

REQUEST:

Reference: Vol. 13, Narrative, Distributed Resource Plan (page 130-132 of 311)

Question: With regards to the timing of NWA identification versus implementation, the Narrative states: "For the Lazy 5 120/25 kV Substation project in 2025, and the Bicentennial Bank 3 and West Tonopah 2nd Bank Addition projects in 2026, the Companies decided that since the constraints and in-service dates for the wired capital upgrade projects were several years in the future, while internal discussion will take place regarding these constraints, no action need be taken at this time to begin any transition to NWA solutions" (emphasis added, page 131 of 311).

Simultaneously, the Narrative identifies "shorter lead times" as a barrier to deferring several planned wired traditional capital upgrade projects, such as the Northwest 120/25 kV Bank #2 Upgrade in 2022, the Topaz Transformer Addition/Upgrade in 2022, the MYS Bank 1 Addition in 2023, and the Tomsik 138/12 kV Bank 1 Addition in 2023 (page 130 of 311).

a. In the Company's opinion, how far in advance should an NWA project be identified to ensure successful project completion, relative to the required in-service date? Please explain the Company's reasoning.

b. In the Company's opinion, how far in advance can an NWA project be identified while still instilling confidence about the financial benefits of the NWA? Please explain the Company's reasoning.

c. Based on parts (a) and (b), in the Company's opinion, what is the optimal window of time between NWA project identification and project in-service date to balance successful project completion and expected financial benefit? Please explain the Company's reasoning.

d. In regards to the proposed Lazy 5 120/25 kV Substation proposed for 2025:

i. The Narrative states that “NV Energy recommends continuing to plan for the construction of... the Lazy 5 120/25 kV Substation...in 2025.” Why does the Company plan to construct the Lazy 5 Substation in 2025 when its own analysis shows that deferring the project could save customers \$9,861,303 in 2025 and \$6,061,606 in 2026 (page 120 of 311)?

ii. How much lead time does the Company expect to need to implement an NWA that would defer the Lazy 5 Substation? Please explain the rationale for the response.

iii. In the Company’s opinion, when would it be appropriate to take action on an NWA to defer the Lazy 5 Substation, assuming any future analyses demonstrate similar cost-effectiveness? Please provide a month and year, and please explain the rationale.

e. In regards to the Bicentennial Bank 3 Addition and the West Tonopah 2nd Bank Addition projects proposed for 2026:

i. For each project, how much lead time does the Company expect to need to implement an NWA that would defer or avoid the grid constraint? Please explain the rationale for the response.

ii. In the Company’s opinion, when would it be appropriate to take action on an NWA to defer or avoid each grid constraint, assuming any future analyses demonstrate similar cost-effectiveness? Please provide a month and year for each project, and please explain the rationale.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

A. NV Energy has not established a specific and consistent lead time necessary for a Non-Wires Alternative (“NWA”) solution to be identified relative to the planned in-service date of a wired capital upgrade project. However, in the NWA analysis process examining constraints on the electric system, the Companies do not consider projects with planned in-service dates within approximately 12 to 18 months from the time that the NWA analysis is being performed. The Companies believe that at this point in the evolution of the NWA analysis process, which is still a maturing process, less than a 12 to 18 month lead time in most situations would be too short to

ensure a successful transition from planning to construct the wired capital upgrade project to deciding on and implementing a NWA solution. Notwithstanding the above, each situation must be examined on a case-by-case basis.

B. NV Energy has not established a specific and consistent lead time beyond which confidence in the cost-effectiveness of a NWA solution compared to a wired capital upgrade project would be suspect. The load forecasts associated with many forecasted distribution system constraints are notoriously variable given that they are reflective of local growth areas in the electric system and minor changes in the timing and magnitude of local load growth can result in significant changes in the required in-service dates for any solutions to mitigate identified constraints. While the continuous process that NV Energy employs in updating the load forecast on substation transformers and distribution feeders ensures the best available forecast information on those facilities, it also presents a challenge to decision-making when variations in the forecast drive changes in required in-service dates of solutions to system constraints. The potential cost-effectiveness of a NWA solution is greatly dependent upon the year it is required and the scope (capacity) of the solution required to defer a wired capital upgrade project.

C. Given that NV Energy's NWA analysis process is still a maturing process, the Companies have not yet established an optimal window of time between NWA project identification and project in-service date to balance successful project completion and expected financial benefit for the reasons discussed in the responses to A. and B. above.

D.i. The Companies acknowledge that the results in DRP-Table 41 for the NWA analysis associated with the Lazy 5 Substation appear quite favorable towards an NWA portfolio solution being more cost-effective than the planned wired capital upgrade project solution. However, there are a few considerations involved with this situation that were not brought forth in the DRP narrative.

First, although the description of the constraint driving the need for the Lazy 5 Substation in the Grid Needs Assessment sections for NV Energy's 2020 and 2021 capital plans in the DRP narrative (refer to pages 54 and 98 of the DRP narrative) focuses on a reliable capacity issue on the Sierra distribution system in that area, the need for the Lazy 5 Substation is also driven by transmission capacity constraints in the larger area in the northern part of the Reno/Sparks area. The Companies note that this component of the constraints involved was not included in the NWA analyses for the Lazy 5 Substation.

Second, the scope of the estimated NWA portfolio solution that would be necessary to potentially defer the substation would be of a magnitude that NV Energy heretofore has not attempted to implement and would carry a commensurate amount of risk in terms of being able to be realistically implemented.

Finally, in comparing the NWA analysis results for the Lazy 5 Substation in DRP Table-18 versus DRP Table-41 it is evident that the results changed dramatically even though the analyses were performed only about a year apart.

Given these facts and that NV Energy expects to perform an updated NWA analysis on the constraints associated with the Lazy 5 Substation at the beginning of 2022, the Companies believe it is prudent to closely monitor the situation while continuing the activities associated

with implementing the Lazy 5 Substation at this time.

D.ii. Please refer to the responses in A. B., and C. above. For the situation with Lazy 5 Substation specifically, the Companies have not yet established an expected lead time for a NWA portfolio required to defer the Lazy 5 Substation. However, considering the scope of the estimated NWA portfolio solution that would be necessary to potentially defer the substation, and that NV Energy heretofore has not attempted to implement a NWA portfolio of such a magnitude, the Companies would expect a comparatively lengthier lead time to implement such a required NWA portfolio as compared to other situations where a smaller capacity NWA portfolio solution would be required.

D.iii. As noted above in the response to D.i., NV Energy expects to perform an updated NWA analysis on the constraint associated with the Lazy 5 Substation at the beginning of 2022. The Companies expect to review the updated results and make a decision whether to begin to take action on a NWA portfolio solution or continue on the path of constructing the Lazy 5 Substation in the planned in-service year directly following that review.

E.i. Since the in-service dates associated with the Bicentennial Bank 3 Addition and West Tonopah 2nd Bank Addition projects are approximately five years in the future, NV Energy has not established specific lead times necessary for potential NWA solutions to the constraints associated with those projects.

E.ii. Assuming that the subject projects are included in NV Energy's 2022 capital plan, the Companies expect to perform updated NWA analyses on the constraints associated with them at the beginning of 2022. Any decision to take action on NWA portfolio solutions will depend upon the results of those updated analyses and the planned in-service years for the wired capital upgrade projects at that time.

CERTIFICATE OF SERVICE

I hereby certify that on this 6th day of October, 2021, I have served the foregoing **DIRECT TESTIMONY AND EXHIBITS OF RAO KONIDENA ON BEHALF OF VOTE SOLAR** in Docket No. 21-06001 upon the persons listed below.

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Dated this 6th day of October, 2021.

/s/ Emma Kaboli
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