2021

Non-Wires Alternative Framework

VERSION 2.0

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1. TABLES AND FIGURES

2. ABBREVIATIONS

BESS:	Battery Energy Storage System
BTM:	Behind the Meter
CHP:	Combined Heat and Power
CPR:	Clean Power Research
CVR:	Conservation Voltage Reduction
DER:	Distributed Energy Resource
DG:	Distributed Generation
DR:	Demand Response
EE:	Energy Efficiency
EG:	Emergency Generation
ENST:	Eversource NWA Screening Tool
EV:	Electric Vehicle
FC:	Fuel Cell
LR:	Load Reducer
MARCS:	Modified Accelerated Cost Recovery System
MG:	Modelled Generation
NWA:	Non-Wires Alternative
PV:	Photovoltaics
SOG:	Settlement Only Generation

3. INTRODUCTION

As part of Docket No. 17-12-03RE07[1], PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternative, Eversource submitted a Written Comments outlining a Non-Wires Alternatives (NWA) Screening Process. Within this process, Eversource identified three (3) main Phases;

a. Technology Screening and Approval
b. NWA Screening Process Per Identified Need
c. Vendor Qualification and Solution Deployment

In Phase II, Eversource calls for a system wide screening of NWA opportunities based on an NWA Screening Tool. This NWA Screening Tool is an Eversource internal development which allows Eversource System Planning to screen capacity project needs at specific locations for potential application of NWA solutions. The intention being, that only sites that are suitable and viable for NWA solutions will move to a more detailed, engineering analysis stage.

The Eversource NWA Screening Tool is designed to enable rapid initial screening of NWA options against traditional system upgrade projects. The NWA Screening Tool will also provide appropriate sizing of such solutions. The objective of the tool is <u>not</u> to provide detailed and accurate costing or technical solution design, but rather to provide a quick, repeatable, scalable process for initial screening of NWA options using levelized cost estimates and basic technical assumptions. To enable this rapid screening, the NWA Screening Tool uses levelized values and standard assumptions for costing of solutions. Furthermore, the NWA Screening Tool only focuses on deferring station capital upgrades and does not incorporate a power flow engine, but rather uses substation load forecasts. Once an NWA solution passes the NWA Screening Tool as a viable solution, Eversource System Planning will still need to perform detailed steady-state and transient analysis studies as well as develop engineering designs and cost estimates for the identified solution at a specific location. And this stage, it is still possible that an NWA solution fails to proceed due to technical issues or cost constraints.

To guide a successfully development of the NWA Screening Tool and screening analysis, Eversource developed this NWA Framework. The NWA Framework describes all the assumptions applicable to the NWA Screening Process. This document represents the Eversource NWA Framework. Within the NWA Framework the following key topics are discussed:

a. **General Assumptions**: Provides an overview of the general assumptions made in the screening process
b. **Reliability Model**: Details how the reliability of NWAs is modeled within the NWA Screening Tool.
c. **Dispatch Model**: Describes dispatch and technical modeling of DERs within an NWA Solution
d. **Cost Model**: Highlights the cost parameters that are used to determine cost of solutions
e. **Revenue Requirements Model**: Provides information on revenue requirements calculations conducted
f. **Revenue Estimation Model**: identifies revenue streams that could be captured by DERs in NWA Solutions

[1]

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5. INITIAL NWA SCREENING

The NWA Framework calls for an initial screening to ensure that from a practical and company policy standpoint the project does not pose any insurmountable obstacles for an NWA Solution before further analysis has been conducted.

A. CRITICAL SUITABILITY CRITERIA

The Critical Suitability Criteria pose a go-no-go decision point in the NWA Screening Process.

a. **Asset Health Index < 0.5**: Any station with a transformer's asset health index above 0.5 will not be considered as an NWA candidate. A health index greater than 0.5 equals a turn insulation drop below 400. (new transformers are at ~1000). Industry/literature[2] accepted practice is that <400 is a replacement candidate.
b. **Year of First Violation ≥ 2**: Any constraint that appears with 2 or less years from the base year will not be considered for an NWA option, as the timeframes for solution design and procurement would not suffice. A standard, out of the box traditional solution provides a faster, and safer alternative to address the issues.

Any project site that does not pass all three criteria will be disqualified from further NWA considerations and Eversource will move forward with developing a traditional solution.

B. ADDITIONAL CONSIDERATIONS

The additional screening considerations are intended to help guide a discussion in case the final cost benefit is close to 1. If any of the additional considerations is answered with a "No", a decision against the NWA solution might be made, but needs to be evaluated on a case by case basis.

a. Is it reasonable to assume at this time that a Non-Wires Alternative can be physically sited in the area?
b. Is it reasonable to assume at this time that there are no environmental concerns with Non-Wires Alternatives in the area?
c. Is it reasonable to assume at this time that local residents would accept a Non-Wires Alternative Solution in the area?
d. Is there no other capital project already approved in the same station?

[2] EPRI 3002019254 Analysis Assessment and Comparison

6. GENERAL FRAMEWORK

The following Chapter outlines the general NWA Framework, including which distributed energy resources (DER) are considered, how reliability is considered, and how forecasts and financial planning horizons are applied.

A. CONSIDERED RESOURCES

The NWA Framework is designed to consider both in front of and behind the meter (FTM / BTM) DER technologies in the NWA Evaluation Process. BTM DERs are assumed to be 3rd party owned and operated through a utility program. Table 1 outlines the DER technologies which are considered in the NWA Framework as options for deferring capital investments.

Table 1: DER Technologies Considered as NWAs

NWA	Definition	Capabilities
Energy Efficiency (EE)	Reduction of load through energy efficiency initiatives in addition to naturally occurring and already planned for energy efficiency.	Reduces load profile overall but limited by availability that is defined by customer makeup
Demand Response (DR)	Temporary reduction of consumption through demand response programs ▪ Commercial DR ▪ Residential DR	Reduces load for a fixed time with pre-conditioning and snap back effects
Photovoltaic (PV)	Solar PV installations ▪ Utility Scale Solar PV ▪ BTM Solar PV	Non-dispatchable output that is dictated by solar irradiance profiles
Battery Energy Storage System (BESS)	Lithium Ion Battery Systems ▪ Utility Scale BESS (Infront of meter) ▪ BTM BESS	System needs to provide enough capacity to recharge during cycles, can provide both active and reactive power
Combined Heat and Power (CHP)	Customer Program CHP solutions incentivized by the Utility Energy Efficiency Program	Modeled to run continuously and generates revenue from electricity and heat. Dispatch capability assumed through Enbala DR Platform
Conservation Voltage Reduction (CVR)	Voltage modification scheme that reduces system voltage to lower system load	Very limited impact which is highly dependent of the feeder makeup and types of loads, typically below 3%
Fuel Cell (FC)	Customer Program FC solutions incentivized by the Utility Energy Efficiency Program	Modeled to run continuously and generates revenue from electricity and heat. Dispatch capability assumed through Enbala DR Platform
Emergency Generation (EG)	Contracted generators (Diesel, Gas, etc.) that can be called upon by the utility	On-call resources with high reliability and flexibility; not renewable, could be noisy and have high emissions; typically, expensive to maintain.

B. FORECASTING AND PLANNING HORIZONS

To allow a technical and economic comparison on a level playing field, solutions are compared not simply with their initial capital need, but over longer time horizons to ensure that they

a. Can meet future capacity needs in a reliable manner
b. Can maintain economic feasibility over longer time spans

As a result, the NWA Framework considers two-time frames, the System Forecast and the Financial Planning Horizon.

SYSTEM FORECAST HORIZON

The System Forecast Horizon describes the timeline over which the EDC can forecast load and generation growth on their system. The NWA Framework assumes a 10-year System Forecast Horizon. Within that 10-year horizon the utility can provide a load growth and DER adoption forecast which allows determination of the expected system peaks. Capacity deficits can only be determined within that 10-year forecasting horizon. As a result, traditional and DER investments can only be made within those ten years. The NWA Framework does not concern itself with the forecasting methodologies but takes a completed forecast as an input for each of the ten (10) years.

The System Forecast Horizon is set at the Base Year + 10 years. The Base Year describes the last year with a complete annual timeseries data set using 15-min interval data.

FINANCIAL PLANNING HORIZON

The Financial Planning Horizon defines the time horizon over which the NWA solution is assumed to be active. Within the Financial Planning Horizon, the tool will automatically track replacement of components, such as battery cells, as needed and O&M costs. The Financial Planning Horizon hereby needs to be larger than

$$\mathrm{FirstConstraintYear} + \mathrm{DeferalYears} - \mathrm{BaseYear} \qquad 06.B.01$$

This is to ensure that the cost of the NWA is considered for the entire time span over which it needs to defer the traditional solution.

The NWA Framework suggests following approach to setting up the Financial Planning Horizon: **Shortest Expected Lifespan**. Using the shortest asset lifespan in addition to the year of construction yields the total financial planning horizon. E.g. with the inclusion of a battery storage system, the shortest expected lifespan is 12 years for the battery cells. The financial planning horizon can now be 12 to 22 years from the base year, depending on when the battery asset is constructed. E.g., the Battery Solution is to be constructed in year 8 of the System Forecast, as a result the Financial Planning Horizon is 8 + 12 = 20 years from the Base Year.

Note: The financial planning horizon needs to reach further at all times than the date to which the traditional solution is deferred.

TERMINAL COST

With a varying Financial Planning Horizon all assets are considered with their entire lifetime revenue requirements impact. For this purpose, the Framework requires revenue requirements up to the financial planning horizon, which includes 1) new investments such as asset replacements as well as O&M, and 2) the terminal cost after the planning horizon which no longer includes O&M or new investments and simply sums the remaining cumulative net present value revenue requirements.

DEFERRING CAPACITY NEED

a. **Deferral within the System Forecast Horizon**: If an NWA solution defers the capacity only so much that the need arises again within the 10-year System Forecast Horizon, a simple value of deferral is calculated using the applicable inflation rate, technology cost reduction, and discount rate to create a change in NPV revenue requirements. Therefore, the NPV of the cost of the NWA solution plus the NPV of the cost of the deferred traditional solution must be less than the NPV of the cost of the traditional solution alone. This is shown in the equation below:

$$\mathrm{NWA(t)_{NPV}} + \mathrm{Traditional(t+n)_{NPV}} \leq \mathrm{Traditional(t)_{NPV}} \qquad \text{06.B.02}$$

where the traditional solution is depreciated over 40 years.

b. **Deferral past the System Forecast Horizon**: With a ten (10) year forecasting horizon, it may happen that an NWA solution is capable of deferring the capacity need past the horizon. In this case, the capacity need is deferred to the first year after the forecast. With a 10-year forecast, the maximum possible deferral is ten (10) years. This limits the value an NWA can produce by deferring capital investments by no more than 10 years, as the assumption is that in year eleven (11) the capital project would be needed.

- **Situational**: Based on the forecast trends and the chosen NWA solution, a decision can be made to declare the deferral to be ≥ 10 years. E.g. if forecasts show a decline

Figure 1 illustrates an example of the application of different timelines in the financial planning model. Hereby, a capacity need at year five (5) is deferred by five (5) years.

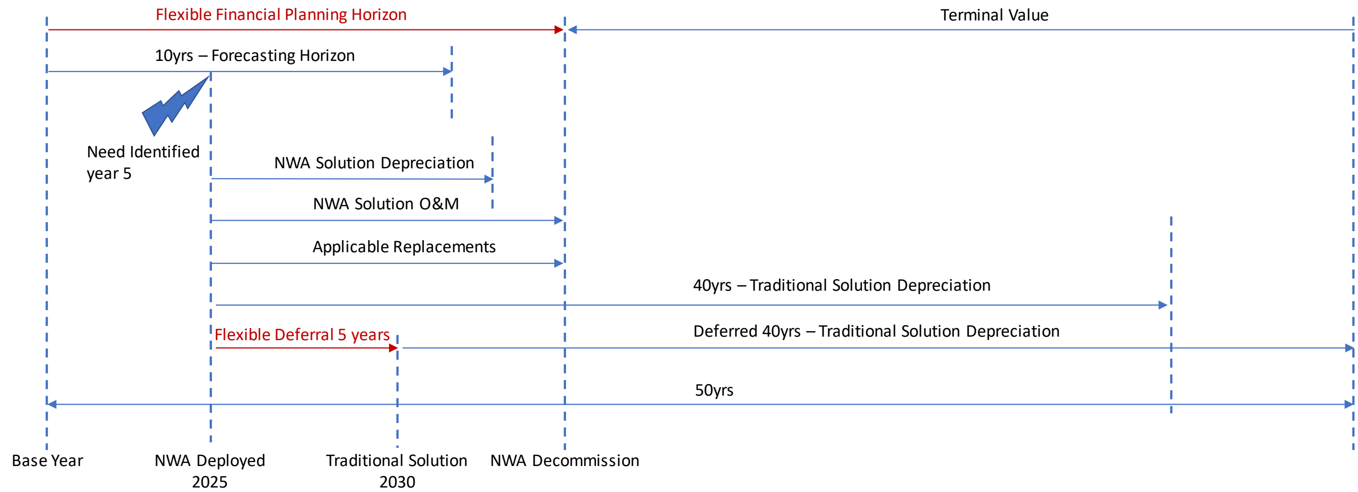

Figure 1: Financial Timelines in NWA Framework

C. NWA DISPATCH OPTIONS

For EDCs to consider DERs as NWAs they need to provide the same level of availability as traditional solutions. While, in most cases, the EDC will be able to forecast high load conditions and the associated dispatch need, unforeseen conditions need to be taken into consideration as well. Such conditions can include storm impacts or other events of natural or human cause that interrupt or disable capacity carrying parts of the system. In such an event, much like the traditional solution counterpart, load might need to be transferred to the NWA on very short notice.

In conclusion, there are two dispatch options

a. **Planned Dispatch**: up to 48-hours ahead, the EDC can determine peak load events and provide dispatch schedules for the NWA to mitigate such situations. This time frame allows the NWA to get "ready" for the dispatch if it is in non-ideal conditions.
b. **Unplanned Dispatch**: the EDC calls upon an NWA within seconds of the actual dispatch due to an unforeseen event of natural or human origin. The NWA does not have time to get "ready" for its dispatch but still needs to provide the full service.

Note: Dispatch option b. is the more limiting for NWA technologies but cannot be excluded from the evaluation criteria, as without it, the EDC needs to provide a contingency for the unplanned dispatch, which would likely be the traditional solution upgrade that the NWA was aiming at deferring in the first place. As a result, several market participation options will not be considered by the Framework specifically because they do not meet this asset readiness standard.

7. RELIABILITY MODEL

In order to assume availability of DERs that are used as an NWA, the company needs to ensure sufficient reserve margin, especially for assets that are controlled through utility owned programs. With NWA assets being part of the electric distribution grid's supply capability, the same N-1 approaches apply as they would to transformers and other hardware.

This section describes the NWA Framework for reliability rules around DERs used for NWA purposes.

A. EXEMPTIONS FROM THE N-1 RELIABILITY DESIGN STANDARD

a. **Energy Efficiency** programs replace existing hardware with newer, more efficient hardware. Once replaced, the new hardware permanently consumes less energy than its predecessor. As a result, Energy Efficiency measures can be exempted from an N-1 design criterion.

b. **Conservation Voltage Reduction** includes the installation of new voltage regulating equipment at the station and along feeder lines. This equipment is not typically designed to N-1 standards, and for the purpose of the NWA Framework, CVR will therefore not be part of any N-1 design criterion.

B. RELIABILITY ASSUMPTIONS FOR CUSTOMER PROGRAMS

For residential customer sited DR, Battery Storage, and Solar assets which are controlled through customer programs an assumption on participation is made. The following equations are utilized to calculate the minimal customer behavior adjusted reliable capacity where the number of assets under contract is (n)

a. Residential Solar

$$P_{PVReliable\_BTM} = \left(\sum P_{PVInstalled\_BTM}\right) * \varepsilon_{capPV}\left(1 - \frac{1}{n}\right) \tag{7.B.01}$$

b. Residential Demand Response

$$P_{DR_{Reliable}} = \left(\sum P_{DRInstalled\_BTM}\right) * \varepsilon_{capDR}\left(1 - \frac{1}{n}\right) \tag{7.B.02}$$

c. BTM Battery Storage

$$P_{BES_{Reliable}} = \left(\sum P_{BESInstalled\_BTM}\right) * \varepsilon_{capBES}\left(1 - \frac{1}{n}\right) \tag{7.B.03}$$

d. **Commercial Demand Response** is treated slightly differently and functions similar to a normal N-1 approach where the largest asset is removed from the overall observation.

$$P_{DRCom_{Firm}} = \left(\sum P_{DRCom_{Reliable}}\right) - \max(P_{DRCom_{Reliable}}) \tag{7.B.04}$$

ε_{cap} represents the saturation limit of distributed DR and PV. For example, if $\varepsilon_{cap} = 0.8$ then no more than 80% of installed assets will ever be accounted for. The following values are used based on historic observations by the Eversource Energy Efficiency Group.

Table 2 shows the respective saturation factor for reliability calculations with

$$\varepsilon = \lim_{n \to \infty} \frac{P_{Available}}{P_{Installed}}$$ 7.B.05

Table 2: Saturated Reliability Factor for Utility Programs

$\boldsymbol{\varepsilon_{capPV}}$	$\boldsymbol{\varepsilon_{capDR}}$	$\boldsymbol{\varepsilon_{capBES}}$
0.95	0.80	0.80

C. RELIABILITY ASSUMPTIONS FOR GRID SCALE BATTERIES

Utility owned and operated grid-scale batteries are considered to be in the same N-1 reliability group as the station's transformers. The resulting capacity which will be considered for grid scale-batteries is therefore calculated as follows

$$P_{Bat_{Firm}} = \begin{matrix} (\sum P_{Bat}); & \max(P_{Bat}) \leq \max\left(P_{Transformer}\right) \\ (\sum P_{Bat}) - \max(P_{Bat})\,; & \max(P_{Bat}) > \max\left(P_{Transformer}\right) \end{matrix}$$ 7.C.01

Note: It is therefore advisable that no single BESS exceeds the size of the largest station transformer as it would be entirely removed for the firm capacity calculation.

D. RELIABILITY ASSUMPTIONS FOR DG

All DG NWA solutions (Solar, Fuel Cell, CHP, Emergency Generators) are considered to be in a separate reliability group. The largest DG is excluded in the NWA Framework to calculate the Reliable DG Capacity $P_{DG_{Reliable}}$ analogous to the transformer + large scale BESS group.

$$P_{DG_{Reliable}} = (\sum P_{DG}) - \max(P_{DG})$$ 7.D.01

DER assets included in P_{DG} are

a. **Solar DG**: For solar DG, $P_{DG_{Solar}}$ represents the installed capacity adjusted for minimal certain weather adjusted output. See Solar Generation for details.
b. **Fuel Cells**: $P_{DG_{FC}}$ represents the nameplate installed capacity
c. **CHP**: $P_{DG_{CHP}}$ represents the nameplate installed capacity
d. **Emergency Generators**: $P_{DG_{EG}}$ represents the nameplate installed capacity

8. DISPATCH MODEL

In order to determine their ability to solve technical issues, the dispatch, especially of flexible resources such as BESS, needs to be accurately modeled. The NWA Framework makes assumptions on DER dispatch modes and capabilities as outlined in the following Chapter

A. PRIORITIZATION OF DER DISPATCH

The NWA Framework assumes that in a multi-solution NWA portfolio, the dispatch priorities are as follows:

a. **Permanently Altering Assets**: These technologies permanently alter the load of the system and are therefore always available and do not require an active dispatch to produce their benefit. The tool will use their contribution first to determine if any remaining dispatch is required.
   - Energy Efficiency

b. **Continuously Running Assets**: Assets that are assumed to be continuously running are considered next. Given the nature of the resources, curtailment of their output would not make fiscal sense. Their contribution is set to nominal throughout the day which is observed. Any remaining capacity need is handled by dispatchable assets.
   - Solar: Has no variable cost and generates revenue when running
   - CHP: Installed through program funding with an assumed dispatch capability through DR system
   - Fuel Cell: Installed through program funding with an assumed dispatch capability through DR system

c. **Dispatchable Assets**: Dispatchable assets can change their dispatch characteristics to the extent that their technical limitations allow them to.
   - **CVR:** Dispatch of tap changers at transformers, capacitors, and in-line voltage regulators with no marginal cost of dispatch
   - **Utility Program Dispatch**: Any utility program, such as DR management, fall under this category
     i. DR (Commercial and Residential DR), limited to one dispatch a day
   - **Utility Owned Asset Optimization and Battery Programs**: Remaining capacity need can be managed by storage. Storage is prioritized before emergency generation assets from an ecological standpoint. This includes the use of Battery Storage DR Programs.
     i. Utility Scale Battery Storage
     ii. BTM Storage Control Programs
   - **Contracted Emergency Assets**: As a last resort emergency generation asset can be dispatched to fill any remaining capacity gap. Their environmental impacts and associated costs make them the least desirable solution.
     i. Emergency Generator

B. SOLAR GENERATION

For consideration of solar distributed generation as an NWA the technology's technical capabilities are defined as follows by the NWA Framework (these apply to both utility scale and BTM installations, their different considerations by the NWA Framework on reliability can be reviewed in 7.D. Reliability Assumptions for DG; any values considered in this section are the result of those reliability assumptions).

a. **Time Variant Output**: Solar PV installations can only generate power during the hours when the sun is shining (typically daytime hours in the U.S.), therefore, any capacity deficits which occur outside those hours cannot be addressed through solar. Solar generation potential is defined through <u>clear sky irradiance profiles</u>[3]. These clear sky irradiance profiles represent ideal weather conditions and change with the day of the year. The following simplified equation is used to determine the P_{DC} panel output over time.

$$P_{DC}(t) = \frac{I_{ClearSky}(t)}{1000\frac{W}{m^2}} * P_{DC_{Rated}} \qquad 8.B.01$$

The Framework does not consider losses or orientation of the solar array and rather assumes ideal conditions for both.

b. **Minimal Weather Adjusted Output (MWAC)**: In order to account for weather conditions and the chance of non-ideal conditions for solar generation, a <u>Minimal Weather Adjusted Relative Irradiance</u> $\varepsilon_{Irr_{MWAC}}$ has been evaluated through data analytics on historic irradiance data sets. A Minimal Weather Adjusted Relative Irradiance shall be used for all three seasons using the 10th percentile on the event distribution.

- **Summer:** Jun, Jul, Aug 16.6%
- **Transition:** Mar, Apr, May, Sept, Oct, Nov 18.1%
- **Winter:** Dec, Jan, Feb 24.1%

The resulting Minimal Weather Adjusted Clear Sky Irradiance Profile can therefore be determined by

$$I_{ClearSky_{MWAC}}(t) = I_{ClearSky}(t) * \varepsilon_{Irr_{MWAC}} \qquad 8.B.02$$

Resulting in a Minimal Weather Adjusted DC Capacity of

$$P_{DC_{MWAC}}(t) = \frac{I_{ClearSky_{MWAC}}(t)}{1000\frac{W}{m^2}} * P_{DC_{Rated}} \qquad 8.B.03$$

No conversion losses are modeled for solar distributed generation, and the $P_{DC_{MWAC}}(t)$ results can be directly converted to the resulting $P_{AC_{MWAC}}(t)$ values as follows. If $P_{DC_{MWAC}} > P_{AC_{Rated}}$, $P_{AC_{MWAC}}$ is capped at $P_{AC_{Rated}}$.

$$P_{AC_{MWAC}}(t) = \max_{P_{AC_{Rated}}} P_{DC_{MWAC}}(t) \qquad 8.B.04$$

c. **Degradation**: The NWA Framework does <u>not</u> account for panel degradation over time but assumes a replacement of panels every 20 years.

Note: The NWA Framework defaults the P_{DC} to P_{AC} ration as 1.2.[4]

Figure 2 shows an application of solar distributed generation to reduce a capacity deficit. Using the evaluation framework for solar distributed generation, this capacity curve was calculated as follows:

a. The plan calls for four (4) systems at $P_{AC_{Rated}} = 2$ MW each; no other DERs are considered
b. The systems are defined as having an $\frac{P_{DC_{Rated}}}{P_{AC_{Rated}}} = 1.5$ ratio
c. The reliability framework accounts for only three (3) of the four (4) systems at 2 MW each, assuming the loss of the largest asset
d. The clear sky irradiance profile is converted to the Minimal Weather Adjusted clear sky irradiance profile and applied to $P_{DC_{MWAC}}$ to calculate $P_{DC_{MWAC}}(t)$ using summer profiles

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[3] The NWA Framework bases its Clear Sky Irradiance data off Clean Power Research's SolarAnywhere® Datasets

[4] Data based on historic trend analysis of large-scale solar system installations in CT

e. In no instance does $P_{DC_{MWAC}}(t)$ exceed $P_{AC_{Rated}}$, therefore there is no capping of the expected output

f. The resulting Minimal Weather Adjusted capacity curve peaks at 3.15 MW, or 39.3% of $P_{AC_{Rated}}$, or 26.3% of $P_{DC_{Rated}}$

g. Due to the time of peak, very little contribution is made by solar to the capacity deficit shown in the example below.

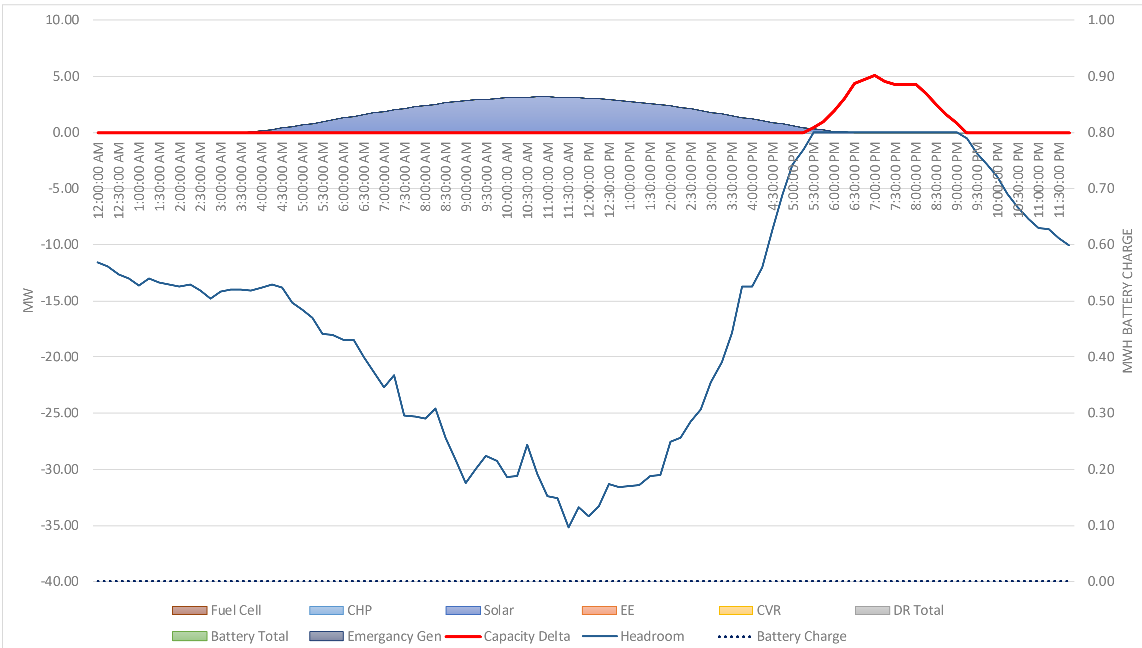

Figure 2: Application of Minimal Weather Adjusted Solar Generation Capacity to a Capacity Deficit

C. ENERGY EFFICIENCY

Energy Efficiency is modeled as a permanent dispatch from the year of installation. This means, that the Energy Efficiency impacts will be modeled as continuously on, regardless of whether there is a capacity deficit or not. Energy Efficiency is modeled for four (4) distinct applications as well as a generic application, each with different profiles. Energy Efficiency is calculated as follows over the course of a day, with $\varepsilon_{Type}(t)$ the Energy Efficiency specific profile type. The Energy Efficiency profiles listed below are based on internal experience of the EE-Team.

$$P_{EE} = \sum_{Type}\left(P_{EE_{Type}} * \varepsilon_{Type}(t)\right) \qquad 8.C.01$$

a. **Lighting**: Lighting Energy Efficiency is assumed to mostly target commercial and industrial lighting, as a result, Energy Efficiency savings will manifest themselves during working hours. Commercial and industrial lighting-based Energy Efficiency will take effect starting at 7am and stop at after 6pm. No seasonal dependency is assumed for Lighting Energy Efficiency measures.

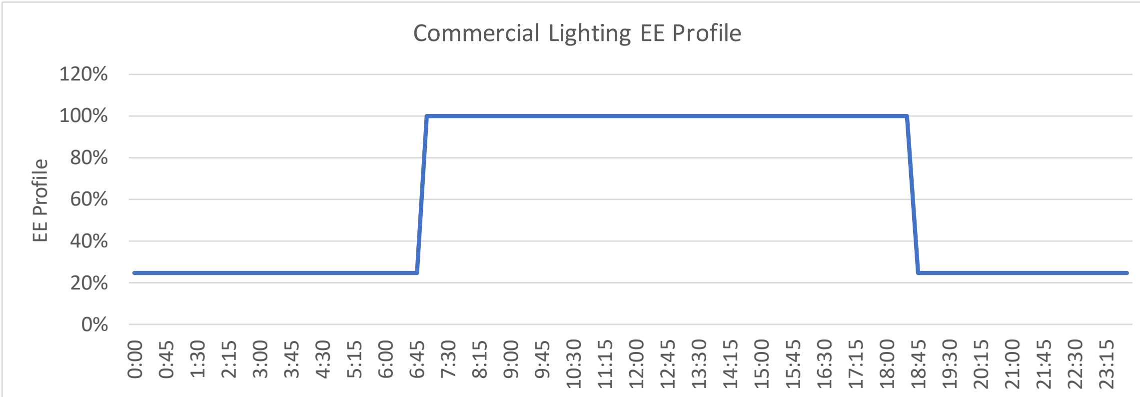

Figure 3: Daily Lighting EE Profile

b. **Residential Lighting**: Residential Lighting is assumed to provide the most impact in the evening hours after 7pm.

c. **HVAC Commercial**: Commercial HVAC is assumed to mostly be active during the day, with minimal activity at night. It is also dependent on the time of year. The underlying assumption is that HVAC load will be the highest during summer months, the lowest during spring and fall, with a minor peak during winter.

To determine the day of year dependency of potential commercial HVAC savings, the following equation applied in the NWA Framework:

$$\varepsilon_{\mathrm{HVAC_{Comm}Yearly}}(t) = 1 + \cos\left(\frac{\text{15 min Interval of the Year}}{\text{Total number of15 min Intervals per Year}} * 4\pi\right) + \frac{1}{3}\sin\left(\frac{\text{15 min Interval of the Year}}{\text{Total number of15 min Intervals per Year}} * \pi\right)$$

8.C.02

which results in the annual curve for HVAC below.

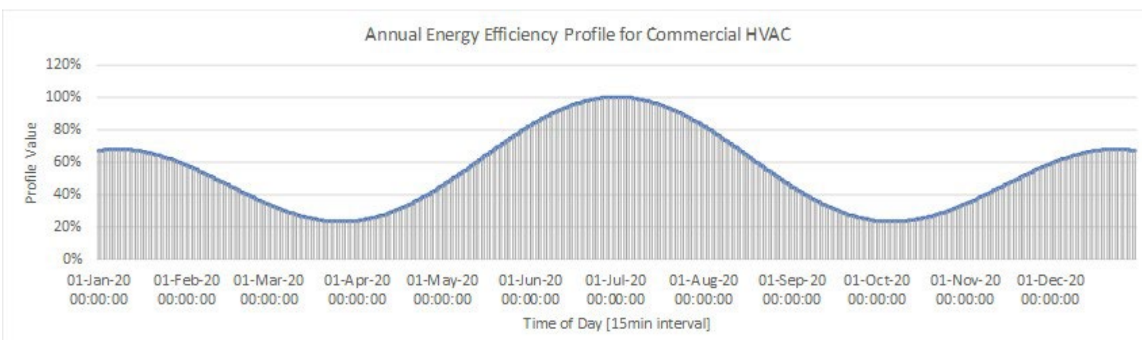

Figure 4: Annual Commercial HVAC EE Profile

For daily profile of commercial HVAC Energy Efficiency,

$$\varepsilon_{\mathrm{HVAC_{Comm}Daily}}(t) = \frac{1}{2}\left(1 + \sin\left(\pi * \frac{\text{15 min Interal of the Day} - 10}{\text{Total number of15 min Intervals per Day}}\right)\right) * \varepsilon_{\mathrm{HVAC_{Comm}Yearly}}(t) \qquad \text{8.C.03}$$

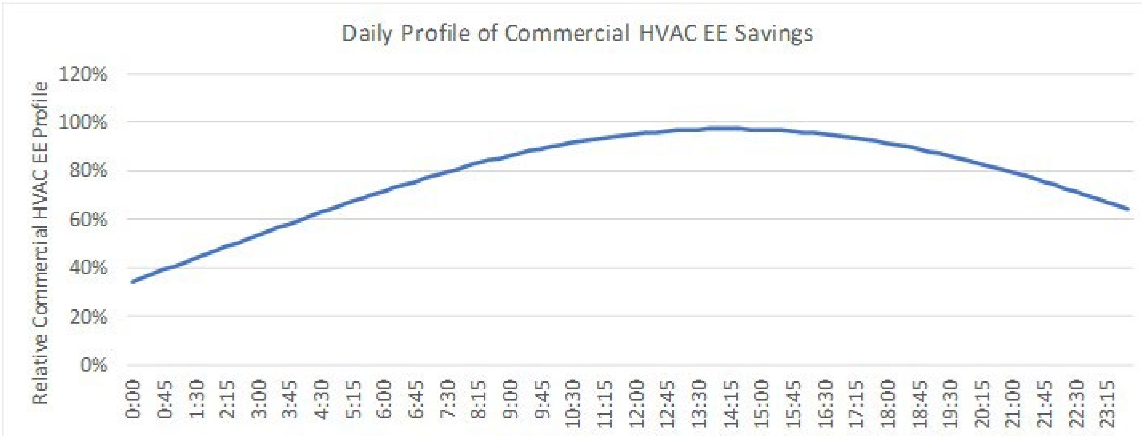

Figure 5: Daily Profile for Commercial HVAC EE

d. **HVAC Residential**: The HVAC residential follows the same yearly distribution as the HVAC commercial application, see above Equation 8.C.02.

$$\varepsilon_{\mathrm{HVAC_{Res}Yearly}}(\mathrm{t}) = \varepsilon_{\mathrm{HVAC_{Com}Yearly}}(\mathrm{t}) \qquad 8.C.04$$

However, given that residential HVAC applications typically have a higher yield in the evening hours and at night as opposed to the commercial HVAC which typically operates during the day, the profile has been adjusted. For the daily profile of residential HVAC, the following profile function is applied.

$$\varepsilon_{\mathrm{HVAC_{Res}Daily}}(\mathrm{t}) = \left(0.7 + \frac{3}{10}\sin\left(2\pi * \frac{\text{15 min Interval of the Day+30}}{\text{otal number of15 min Intervals per Day}}\right)\right) * \varepsilon_{\mathrm{HVAC_{Res}Yearly}}(\mathrm{t}) \qquad 8.C.05$$

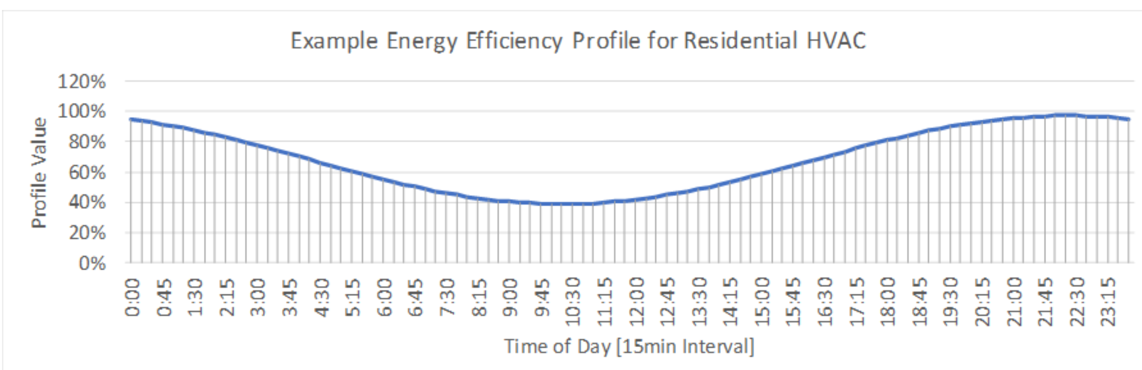

Figure 6: HVAC Residential HVAC EE Profile

D. DEMAND RESPONSE

Demand Response (DR) is classified into two types, commercial and residential DR. Both types of DR will dispatch automatically if there is a modeled capacity delta. The dispatch is modeled as a binary function, activating all of the resources or none.

DR contracts provide for a 3-hour dispatch minimum window. Longer dispatch windows can be simulated, but an adjustment to the overall DR volume needs to be made, as the EDC would then stagger the DR resources to achieve such an effect.

SNAP BACK AND PRE-CONDITIONING

Both DR resource types are modeled with pre-conditioning (e.g. through precooling before an event) and a snap back (e.g. through re-cooling after an event).

a. **Pre-Cooling** lasts 30 min and is defaulted to 60% of the total DR impact and is user adjustable depending on local conditions
b. **Snap Back** lasts for 2 hours after the event and is defaulted to 60% of the total DR impact and is user adjustable depending on local conditions

Figure 7 shows a modeled DR event with 2 MW of commercial, and 0.5 MW of residential DR capacity. Clearly visible, the pre-conditioning and snap back, before and after the event respectively.

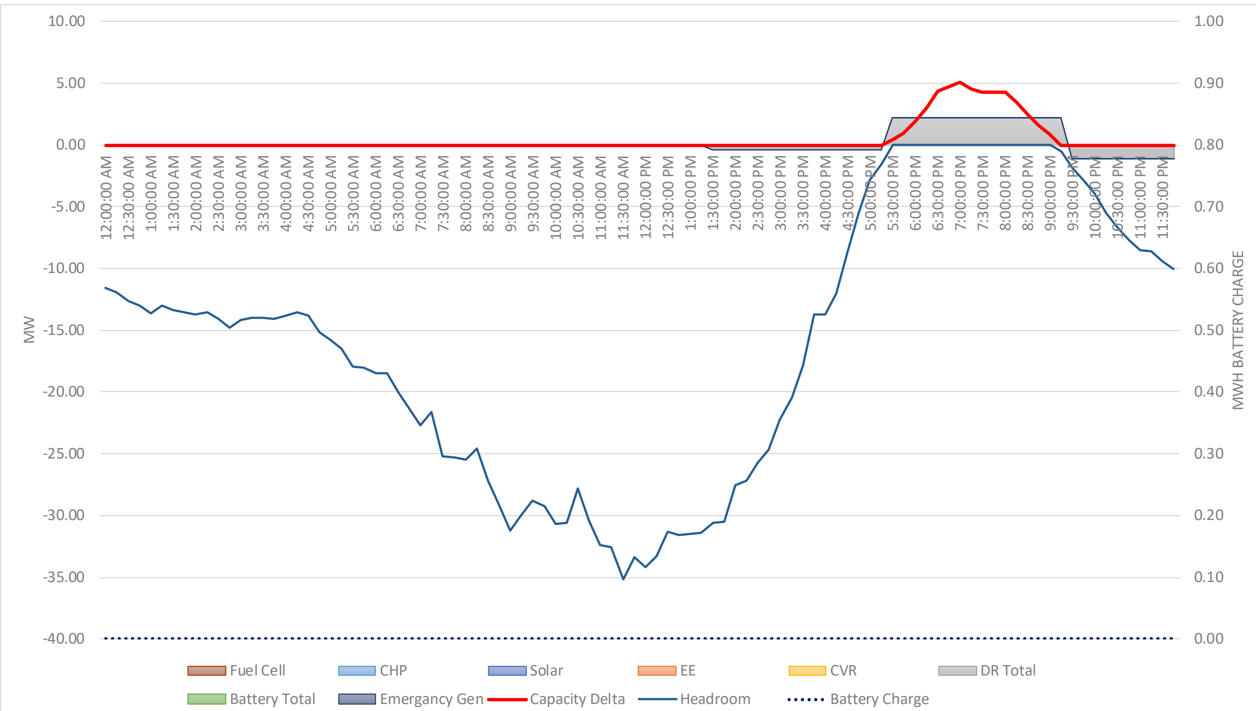

Figure 7: Example DR Event with Pre-Conditioning and Snap Back

AVAILABILITY OF DR RESOURCES

DR resources, much like EE, are only available if the underlying load is actually being used. For EE, the Framework models this approach with a seasonal and intra-day dependency. For commercial and residential DR, the NWA Framework provides a similar approach. As both forms of DR (excluding BTM storage) are typically based on HVAC applications, their highest impact will be achieved during peak summer month during afternoon hours. Figure 8 highlights the peak availability of DR resources throughout the year assumed in the NWA Framework.

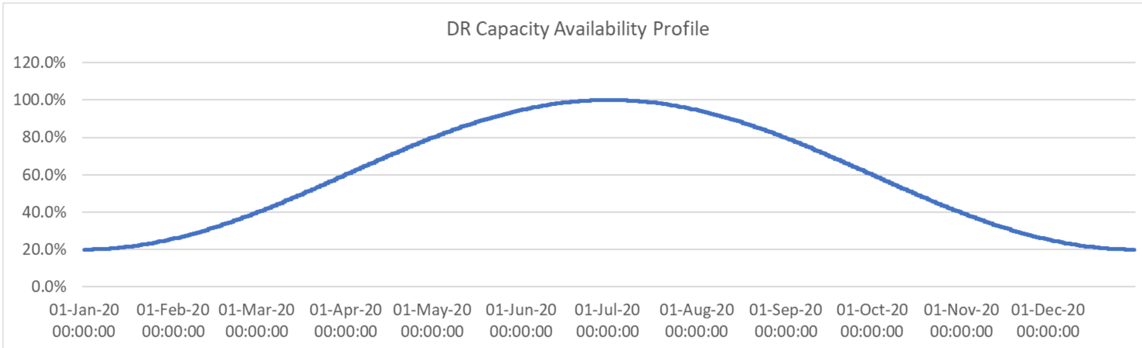

Figure 8: Annual DR Capacity Availability Profile

For each individual day, the Annual DR Capacity Availability Profile provides the peak DR response that can be expected based on the contracted volume. All contracted volume is given at 100% Annual DR Capacity. For each individual day, the value is then scaled to a daily profile to match actual resource usage. Figure 9 shows the Framework's availability profile for commercial and residential DR resources.

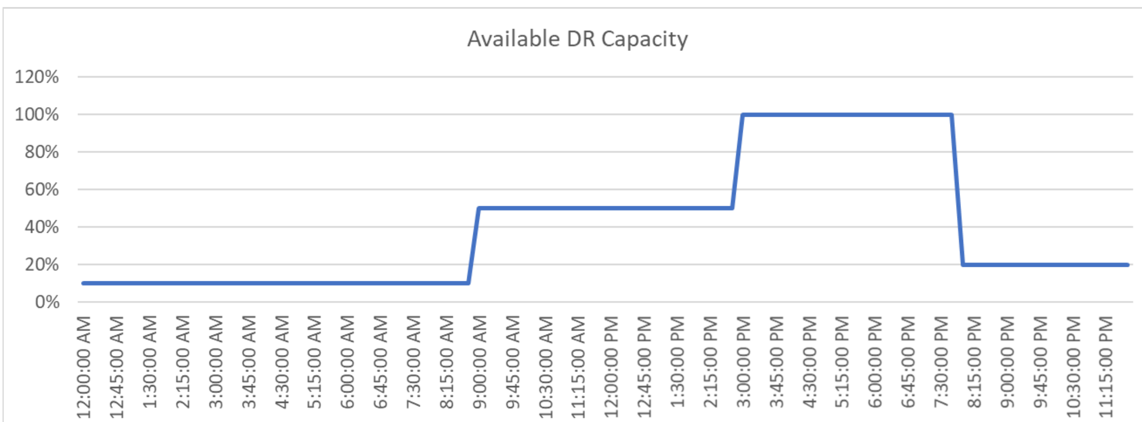

Figure 9: Available DR Capacity Profile

E. CONSERVATION VOLTAGE REDUCTION

Conservation Voltage Reduction (CVR) is given as a percentage of feeder load and as such varies over time. During a low load situation CVR will consequently reduce the load less in absolute numbers, than it does during a high load situation. The default assumed maximum reduction value is 1.8%, which is lower than the 2.34[5] reported by EPRI (only report with more constant impedance loads), but the number can be changed depending on the feeder topology and load constellation. The 1.8% represents values evaluated by the Company on its own circuits and requires a high-level evaluation for each region to ensure that such targets can be reached.

F. BATTERY STORAGE

For the purpose of technical evaluation all available battery resources are dispatched in the same manner. Hereby no distinction is made between grid scale battery systems and BTM solutions. Further, only battery resources that are under direct control of the utility are considered as NWA options, both utility scale and behind the meter.

Battery dispatch is constrained by:

a. **Maximum Charging/Discharging Power**: It is assumed that a battery has a symmetric dispatch and can achieve its full rated power both when charging or discharging and is limited only by the inverter capabilities. No reactive power dispatch will be taken into consideration.
b. **Available Headroom**: The battery will <u>not</u> (dis)charge in a fashion that introduces new capacity violations, therefore, recharge limitations are in place and a battery might find itself in a situation where it cannot recharge fast enough to support a new capacity constraint. It will take into consideration any additional capacity from Permanently Altering and Continuously Running Assets (See Section 8.A.)
c. **Capacity Deficit**: The battery will <u>not</u> (dis)charge more than is required to eliminate a capacity deficit. This means, only the absolute required minimum usage of the battery is assumed, which would equal ideal conditions.
d. **State of Charge**: The battery cannot charge, or discharge more than its state of charge allows. Batteries are assumed to be able to charge between 0% and 100% of their nameplate capacity. All the batteries are given an initial state of charge for the peak day simulation. That initial state of charge can be freely chosen[6] by the user. The dispatch simulation requires the batteries to return to the same SOC at the end of the simulated day, to ensure same initial condition should the following day also require battery dispatch for NWA purpose. The default setting here is 50%, stating that the battery starts, and ends, each day at 50% state of charge.
    a. **IMPORTANT**: If the battery is unable to attain at least the same SOC at the end of the peak day that it started the day with, it is at <u>high risk of not being able to perform two consecutive event days</u>. This means that the station does not have enough headroom to allow adequate recharging of the BESS.
e. **Degradation**: No degradation of storage capacity is applied in the NWA Framework
f. **Round Trip Efficiency**: A round trip efficiency is defined in the NWA Framework, which is applied equally to the charging and discharging cycles with

$$\sqrt[2]{\%_{\mathrm{roundtrip}}} \qquad \text{8.F.01}$$

[5] https://www.epri.com/research/products/1024482

The charge and discharge efficiency are taken into consideration for SOC modeling, energy loss calculations, and when determining the ideal system size.

If any capacity deficit cannot be met by the battery, either because it does not have sufficient power, or because it has run empty, this will be highlighted.

G. FUEL CELL

Fuel Cell units are assumed to be must run assets and are modeled as continuously running. See Chapter 6.A and 9.K. The NWA Framework assumes that, outside of reliability considerations, any downtime for Fuel Cells will be maintenance-related and scheduled outside of possible event days.

H. COMBINED HEAT AND POWER

Combined Heat and Power (CHP) units are assumed to be must run assets and are modeled as continuously running. The NWA Framework assumes that, outside or reliability considerations, any downtime for CHPs will be maintenance-related and scheduled outside of possible event days.

I. EMERGANCY GENERATION

Emergency Generation units are dispatched to compensate any capacity deficits. Their dispatched is modeled as binary, either on or off. They are not modeled to require warm up or spool down times as the resolution of the NWA Framework is 15 min, which provides adequate time for a generator to reach operational output. Aside from N-1 considerations, Emergency Generators are modeled at name plate rating.

9. COST MODEL

For the NWA Framework, the Cost Model describes how costs of all types of solutions, NWA and traditional are modeled. For all NWA solutions, the same cost model is applied (with the exception of CVR). Where an NWA solution does not have a cost factor, the values are considered null.

A. TRADITIONAL SOLUTION

Traditional Solution cost is provided in the NWA Framework in three categories

a. **CapEx**: Capital Expenses for traditional solutions are provided for a single year of expense; the NWA Framework assumes for simplicity reasons that all cost can be allocated to a single year. The Framework provides for entries in the following fields, which are all summed up to be included in the total CapEx of the project:
    a. Labor and Equipment
    b. Engineering
    c. Material
    d. PM Support / Permitting
    e. Removal
    f. Contingency
    g. Escalation
    h. Indirects
    i. AFUDC

b. **OpEx**: Operational Expenses are provided starting the year of the project and represent any increase or decrease in OpEx due to the new solution. A decrease in OpEx due to a new traditional solution can also be included as a negative value. Any change in OpEx will be extrapolated forward over the full financial planning horizon.

c. **Real-Estate Cost**: Any property purchases required are recorded separately. An annual addition to the revenue requirements is made through multiplication of the sum of all property purchases made to that point in time, multiplied by the WACC

$$\mathrm{WACC} * \sum_{1}^{t} \$_{\mathrm{PropertyPurchase}}(\mathrm{t}) \qquad 9.A.01$$

B. NWA COST TYPES

The NWA Framework accounts for four (4) types of cost when it comes to DERs under consideration for NWA opportunities.

a. **CapEx Cost:** Capital Expenses (CapEx) are treated as expensed in a single year for any DER project. E.g., the installation of a battery system carries $5.5 Million CapEx cost. Even if the project to build said battery system might, in reality take more than a year, the Framework assumes those costs occur in the year the solution is deployed.
    - CapEx costs are increased on a yearly basis using a general inflation rate
    - CapEx costs have a book depreciation over the asset's life span (12, 20, or 40 years)
    - CapEx costs have a tax depreciation over either 5, 7, or 20 years
    - CapEx costs for specific asset types have a technology cost reduction, such as solar panels

    CapEx Cost includes the following line items in the cost model for each type of NWA

- **Equipment Cost:** Includes all NWA asset equipment, such as generators, panels, or inverters. Reappears for an asset replacement. Given in $^{\$}/_{\mathrm{MW}}$. For accounting purposes (see Chapter 10.A. Accounts), these costs are split between the following positions where applicable
    - **Distribution Hardware**
    - **Inverters**
    - **Generators/Motors/CHP/Fuel Cells**
    - **Battery Cells**
- **Interconnection Equipment:** Includes all equipment required to interconnect the asset. Does not re-appear for an asset replacement. Given in $^{\$}/_{\mathrm{MW}}$
- **Replacement Cost:** For NWA solutions with a lower life span than financial planning horizon, a replacement of the Equipment cost is considered in addition to a labor factor. Given in $^{\$}/_{\mathrm{MW}}$
    - **Battery Cells** are replaced after 12 years
    - **Inverters** are replaced after 20 years
    - **Solar Panels** are replaced after 20 years
    - **Generators, CHP, and Fuel Cells** are replaced after 20 years
    - **All Other Hardware** is replaced after 40 years
- **Engineering, Installation, and Commissioning:** All labor associated with the installation of the Equipment and the Interconnection. This includes labor, EPC overhead, and any interconnection costs with the utility. Given in $^{\$}/_{\mathrm{MW}}$
- **Overhead:** Project management and internal overhead for projects. Given in % of other CapEx cost where *x* represents the respective CapEx cost components as (for battery systems, the includes the battery cell component cost)

$$\sum\left(\mathrm{P_{inst}} * \mathrm{x}\frac{\$}{\mathrm{MW}}\right) \qquad 9.B.01$$

b. **OpEx Cost:** Operational Expenses (OpEx) are treated as expenses reoccurring every year. Reoccurring cost, program or OpEx, are calculated on a yearly basis.
- OpEx costs are increased on a yearly basis using a general inflation rate
- OpEx costs are treated as a direct passthrough to revenue requirements without additional earnings add on

OpEx Cost include the following line items in the cost model for each type of NWA
- **Fixed O&M**: Includes all maintenance and minor replacement activities, in addition to any running cost that are not dependent on utilization.
- **Variable O&M**: Includes all fuel and other variable cost that is dependent on either the energy produced or the Full Load Hours of operation per year.
- **Full Load Hours**: For variable O&M this represents the assume ratio of $\frac{\frac{\mathrm{Energy}}{\mathrm{Year}}}{\mathrm{P_{inst}}}$

c. Real-estate Cost: Real-estate cost can come into consideration for traditional solutions, grid scale solar DG and storage systems. Investments into properties cannot be depreciated, but will be accounted for with WACC
- Real-estate costs are increased with the yearly inflation rate

d. Program Costs: There are two types of Program Costs, reoccurring, such as costs created through Demand Response Programs, and one-time program costs, such as for the deployment of energy efficiency measures
- **One Time Program Cost:** Added to the OpEx costs the year they are incurred with an earnings multiplier
- **Reoccurring Program Cost:** Added to the OpEx cost every year they are incurred with an earning multiplier
- Program Costs are <u>not</u> increased on a yearly basis using a general inflation rate

C. ANNUAL RATES OF CHANGE

All values in the NWA Framework are provided in nominal values. To account for inflation, and the reduction in cost for certain technologies, the NWA Framework provisions for annual rates of change for the following

a. **Inflation Rate**: The inflation rate is defaulted to 2% an applies to all hardware, labor, real estate and O&M costs. Program costs are excluded from inflation

b. **Discount Rate**: The discount rate is given as a nominal discount rate and defaulted to -3.37%[7]. The effective discount rate is calculated, depending on the year the expense happens as

$$(100\% + \varepsilon_{\text{Discount Rate}} + \varepsilon_{\text{Inflation Rate}})^{\text{t}-\text{Base Year}} \tag{9.C.01}$$

c. **Cost Rate PV Panels**[8]: The cost rate for PV Panels provides a projection of cost development of PV Panels <u>instead</u> of the inflation rate. PV Panels are not subject to the inflation rate but adhere to changes based on the Cost Rate for PV Panels. The NWA Framework defaults this value at -4.0%

d. **Cost Rate Battery Cells**[9]: The cost rate for Battery Cells provides a projection of cost development of Battery Cells <u>instead</u> of the inflation rate. Battery Cells are not subject to the inflation rate but adhere to changes based on the Cost Rate for Battery Cells. The NWA Framework defaults this value at -5.0%

e. **Cost Rate Inverters**[10]: The cost rate for Inverters provides a projection of cost development of Inverters <u>instead</u> of the inflation rate. Inverters are not subject to the inflation rate but adhere to changes based on the Cost Rate for Inverters. The NWA Framework defaults this value at 6%. This value applies to both Battery and Solar inverters. While the NREL report highlights a 2019 price increase of 20% for utility scale central inverters, that number will most likely not be sustainable.

Table 3: Application of Annual Change Rates Based on Cost Component

Component	Inflation Rate	Discount Rate	Cost Rate Panels	Cost Rate Cells	Cost Rate Invert.
Real Estate	X	X			
Traditional	X	X			
Int. Hardware	X	X			
Any O&M	X	X			
Inverters	X	X			X
Battery Cells	X	X		X	
Solar Panels	X	X	X		
Gen., FCs, CHP	X	X			
Program Costs		X			
Electricity Cost	X	X			

[7] https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf

[8] NREL Q4 2019/Q1 2020 Solar Industry Update Page 39

[9] NREL Cost Projections for Utility-Scale

[10] NREL Q4 2019/Q1 2020 Solar Industry Update Page 64

Note: All technology rates of change can be edited within the NWA Screening Tool to adjust to the ever-changing landscape. To provide a unified source of information, the NWA Framework uses NREL's publications[11]

D. EARNING FACTORS UTILITY PROGRAMS

For energy efficiency and demand management expenditures, the Company has the ability to earn a performance incentive averaging 5% of total program expenditures. Therefore, for purposes of modeling within the NWA solution the following rates are applied by state.

Note: Historic assumption is based on the level of generated benefits as a percentage of spend and depending on jurisdiction.

Table 4: Program Performance Incentive

State	MA	CT	NH
Assumed Performance Incentive	5.0%	5.0%	5.0%

These values are applied to:

a. Demand Response Programs, <u>annually</u>
   a. Commercial
   b. Residential
   c. Battery Storage
b. Energy Efficiency Programs, <u>once</u>
c. Behind the Meter Solar Programs, <u>annually</u>

E. LIFE CYCLE ASSUMPTIONS

For the cost calculation, the NWA Framework makes assumptions on the useful life of an asset. This is achieved within the NWA Framework by clustering assets into three (3) expected useful life spans

Table 5: Life Cycle Assumptions by Asset Type

Asset Type	12-Year Assets	20-Year Assets	40-Year Assets
Traditional Solution			X
Interconnection Hardware			X
Inverters		X	
Battery Cells	X		
Solar Panels		X	
Generators, FCs, CHP		X	

The Life Cycle Assumptions will inform the calculation of the Revenue Requirements through the tax and book depreciation, as well as MACRS values.

[11] NREL Annual Technology Baseline

If, within the financial planning horizon selected, an asset reaches the end of its useful lifespan, it is assumed replaced by the NWA Framework with an addition investment happening in the last year of its expected lifespan. This process can, depending on the asset and the Financial Planning Horizon, happen more than once.

F. SOLAR GENERATION

For the NWA Framework, cost assumptions have been made for the cost of solar systems to supply default values.

UTILITY SCALE SOLAR GENERATION[12][13]

a. CapEx Cost

- Equipment Cost:
  - i. Panels $\$340{,}000/_{\mathrm{MW}}$
  - ii. Solar Inverter (2 Quadrant) $\$62{,}000/_{\mathrm{MW}}.$
- Interconnection Equipment: $\$330{,}000/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at $\varepsilon_{\mathrm{Replace}} = 20\%$
- Engineering, Installation, and Commissioning: $\$240{,}000/_{\mathrm{MW}}$
- Overhead: 50%

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$50{,}000/_{\mathrm{a}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $1400\mathrm{h}/_{\mathrm{a}}$

c. Real-Estate Cost: $\$0.00$

d. Program Costs

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MW}}$

With different sizes between inverters and panels, the cost model accounts for the Equipment Cost as follows

$$\$470{,}000/_{\mathrm{MW}} * \mathrm{P}_{\mathrm{inst}_{\mathrm{DC}}} + \$50{,}000/_{\mathrm{MW}} * \mathrm{P}_{\mathrm{inst}_{\mathrm{AC}}} \qquad 9.F.01$$

Where. For the NWA Framework, a default overclocking rate $\varepsilon_{\mathrm{OC}}$ is assumed for all solar generation, this value is defaulted to

$$\varepsilon_{\mathrm{OC}} = 1.2 \qquad 9.F.02$$

[12] https://atb.nrel.gov/electricity/2019/index.html?t=su

[13] Solar Energy Industries Association, US Solar Market Insight, Full Report, Q4 2020

BEHIND THE METER SOLAR GENERATION:

The NWA Framework considers that behind the meter solar generation could provide an NWA to traditional utility investments in certain situations as part of a utility-managed program. However, current incentive structures available to behind the meter solar applications generally do not incentivize solar installations on a location-specific basis in order to ensure that installation would provide a benefit to the distribution system as an NWA.

a. CapEx Cost

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$.
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: N/A

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $1400\mathrm{h}/_{\mathrm{a}}$

c. Real-Estate Cost: $\$0.00$

d. Program Costs

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$35/_{\mathrm{a} * \mathrm{MW}}$

G. ENERGY EFFICIENCY

Energy Efficiency is conducted as a utility program with the assumption that all expenses happen in a single year, and that no continuous expenses are required.

a. CapEx Cost

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$.
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: N/A

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: N/A

c. Real-Estate Cost: $\$0.00$

d. Program Costs

- One Time Program Cost $\$50/_{10\mathrm{a} * \mathrm{MWh}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MW}}$

The cost of energy efficiency programs is determined by through a $/kWh saved metric ε_{EE}, with

$$\varepsilon_{EE} = 50 \frac{\$}{MWh*10a} \quad 9.G.01$$

To calculate the cost of the total Energy Efficiency program, the savings over a ten (10) year time span are considered in the NWA Framework, resulting in an Energy Efficiency program cost of

$$EE_{cost} = \varepsilon_{EE} * 10a * \int_0^{365} EE_{kWh} dd \quad 9.G.02$$

Where the savings are calculated over all days of the year using the Energy Efficiency Profiles.

All Energy Efficiency cost is incurred at the year on inception with no running cost. In addition, a Utility Earnings Factor, see Chapter 9.D. is applied to the cost.

$$EE_{RevReq} = EE_{cost} * (1 + \varepsilon_{Earning}) \quad 9.G.03$$

There is no inflation assumed for the cost of Energy Efficiency programs

H. DEMAND RESONSE

Demand Response Programs are, as part of the NWA Framework, modeled with a cost per kW. In reality, there is a performance factor applied, with some assets no performing at all events, or not to full specification. However, for the NWA Framework, some assumptions have been made to simplify the modeling

a. The assumption is that the assets are fully able to perform. As a result, the cost for DR programs can be reduced to an annual capacity payment without a performance component.
b. Unlike Energy Efficiency, DR costs are annual costs that continue to present over the course of the financial planning horizon.
c. Demand Response program costs are excluded from an inflation rate in the NWA Framework
d. Programs working with storage do not account for replacement of cells or batteries. That cost is covered by the owner and accounted for in the annual payments.

COMMERICAL

For commercial DR, the capacity payments are set at

a. CapEx Cost

- Equipment Cost: $\$0.00/_{MW}$.
- Interconnection Equipment: $\$0.00/_{MW}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{MW}$
- Overhead: 0%

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{a*MW}$
- Variable O&M: $\$0.00/_{MWh}$
- Full Load Hours: N/A

c. Real-Estate Cost: $\$0.00$

d. Program Costs

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$50{,}000/_{\mathrm{a}*\mathrm{MW}}$

Commercial DR contracts are limited to <u>eight (8) events a year</u> and can be expanded to include more events per year at an additional cost per kW. The event limit numbers are based on DR contracts as they are currently used by the company. To compute additional costs for larger DR contracts, the Framework defaults to an assumed surcharge of 50%.

$$\text{Total Events} - \text{Maximum Contract Events} \geq 0 \tag{9.H.01}$$

$$\varepsilon_{\mathrm{DR_{Com}}} * \left(1 + 50\% * \frac{\text{Total Events} - \text{Maximum Contract Events}}{\text{Maximum Contract Events}}\right) \tag{9.H.02}$$

Resulting in a cost of

$$50{,}000 \frac{\$}{\mathrm{kW}} * \left(1 + 50\% * \frac{16-8}{8}\right) = 75{,}000 \frac{\$}{\mathrm{kW}} \tag{9.H.03}$$

The program is scaled to the year with the largest number of events in the forecasting horizon

RESIDENTIAL

For residential DR, the capacity payments are set at

a. CapEx Cost:

- Equipment Cost: $\$0.00/_{\mathrm{MW}}\cdot$
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: 0%

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a}*\mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: N/A

c. Real-Estate Cost: $\$0.00$

d. Program Costs:

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$120{,}000/_{\mathrm{a}*\mathrm{MW}}$

Residential DR contracts are limited to <u>16 events a year</u> and can be expanded at a cost rate of 50% using the same methodology as the commercial DR contracts, see Equation 9.H.03

The program is scaled to the year with the largest number of events in the forecasting horizon

STORAGE

For storage DR, the capacity payments are set at

a. CapEx Cost:

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: 0%

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a*MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: N/A

c. Real-Estate Cost: $0.00

d. Program Costs:

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$250{,}000/_{\mathrm{a*MW}}$

Battery DR contracts are limited to <u>60 events a year</u> and can be expanded at a cost rate of 50% using the same methodology as the commercial DR contracts, see Equation 9.H.03

The program is scaled to the year with the largest number of events in the forecasting horizon

I. CONSERVATION VOLTAGE REDUCTION

CVR programs provide for a slightly altered cost structure. Based on the Company's experience, the cost to implement a CVR program at a Substation is highly variable based on present equipment, but is defaulted to

$$\varepsilon_{\mathrm{CVR}_{\mathrm{Install}}} = 2{,}500{,}000\,\frac{\$}{\mathrm{Substation}} \tag{9.I.01}$$

And takes an average of 12-man hours a week to operate, which results in an annual cost of

$$\varepsilon_{\mathrm{CVR}_{\mathrm{O\&M}}} = 78{,}000\,\frac{\$}{\mathrm{Substation}*\mathrm{a}} \tag{9.I.02}$$

J. BATTERY STORAGE

For battery storage solutions, the cost assumptions are based on NREL publications[14].

a. CapEx Cost:

- Equipment Cost: The default value Battery Storage is at
  i. Battery Cells $\$209{,}000/_{\mathrm{MWh}}$

[14] https://atb.nrel.gov/electricity/2019/index.html?t=st based on 2-hour storage systems

ii. Battery Inverter (4 Quadrant) $\$70{,}000/_{\mathrm{MW}}$

- Interconnection Equipment: $\$100{,}000/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at $\varepsilon_{\mathrm{Replace}} = 20\%$
- Engineering, Installation, and Commissioning: $\$62{,}500/_{\mathrm{MW}}$
- Overhead: 50%

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$50{,}000/_{\mathrm{a}}$
- Full Load Cycles N/A

c. Real-Estate Cost: $\$0.00$

d. Program Costs:

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MWh}}$

Note: Variable O&M for BESS is based on energy losses and cost of energy

K. FUEL CELL

Fuel Cells are modeled as Commercial Fuel Cells with the following cost components in the NWA Framework. For the NWA Framework, they will be considered as part of the Energy Efficiency portfolio. The following outlines the default values assumed in the cost model.

a. CapEx Cost

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$.
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: N/A

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $6000\mathrm{h}/_{\mathrm{a}}$

c. Real-Estate Cost: $\$0.00$

d. Program Costs

- One Time Program Cost $\$700\,000/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MW}}$

L. COMBINED HEAT AND POWER

CHPs are modeled as Commercial – Natural Gas Microturbines with the following cost components in the NWA Framework. They are deployed through incentive programs managed under the Energy Efficiency portfolio.

e. CapEx Cost

- Equipment Cost: $\$0.00/_{MW}$.
- Interconnection Equipment: $\$0.00/_{MW}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{MW}$
- Overhead: N/A

f. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{a * MW}$
- Variable O&M: $\$0.00/_{MWh}$
- Full Load Hours: $6000h/_{a}$

g. Real-Estate Cost: $0.00

h. Program Costs

- One Time Program Cost $\$1\ 000\ 000/_{MW}$
- Reoccurring Program Cost $\$0/_{a * MW}$

M. EMERGENCY GENERATION

Emergency Generation typically represents 3rd party owned and operated Diesel or Natural Gas Generators which an EDC secures under contractual obligation. These contracts include annual capacity payments as well as variable payments depending on the rate of utilization.

a. CapEx Cost:

- Equipment Cost: The default value for Fuel Cells is at $\$0/_{MW}$
- Interconnection Equipment: $\$0/_{MW}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0/_{MW}$
- Overhead: N/A

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$270{,}000/_{a * MW}$
- Variable O&M: $\$400/_{MWh}$
- Full Load Hours N/A

c. Real-Estate Cost: $0.00

d. Program Costs:

- One Time Program Cost $\$0/_{MW}$
- Reoccurring Program Cost $\$0/_{a * MWh}$

10. REVENUE REQUIREMENTS

The NWA framework includes representative revenue requirement calculations in order to compare the potential ultimate cost to customers of NWA and traditional solutions. Further detailed financial analysis would be conducted prior to the Company implementing any solution and amounts sought for recovery by the Company would also be based upon more detailed revenue requirement calculations.

A. GENERAL ASSUMPTIONS

For the NWA Framework, a simplified approach was chosen to evaluate the revenue requirements stemming from certain investments.

ACCOUNTS

The following accounts and Modified Accelerated Cost Recovery System (MACRS) depreciations are considered:

a.	**345** Inverters	5 Years
b.	**344** Solar Panels/Generators	5 Years
c.	**362** Distribution Station Equipment	20 Years
d.	**363** Storage Battery Equipment	7 Years

For the book depreciation, the following equipment lifespans are considered

a.	Battery Cells	12 Years
b.	Solar Panels, Inverters, Generators, Fuel Cells, CHP	20 Years
c.	All traditional hardware	40 Years

The resulting combinations for assets are

a.	**7/12**	Battery Cells
b.	**5/20**	Solar Panels, Inverters, Generators, Fuel Cells, CHP
c.	**20/40**	All traditional hardware

DEPRECIATION ACCRUAL RATE

The Framework provisions the accrual rate as

$$\frac{1}{\text{Asset Useful Life (years)}} \qquad \text{10.A.01}$$

PRE-TAX WACC

The Pre-Tax Weighted Average Cost of Capital (WACC) are calculated as follows

a. Using a Federal Tax Rate of 21% and a state rate per selected state the Effective State Rate is calculated as

$$\text{State Rate} * (1 - \text{Federal Rate}) \qquad \text{10.A.02}$$

b. The Effective State and Federal Tax Rate is the calculated by

$$\text{Federal Rate} + \text{Effective State Rate} \qquad \text{10.A.03}$$

c. The Net Income After Taxes on Income is

$$1 - \text{Effective State and Federal Tax Rate} \tag{10.A.04}$$

d. The Pre-Tax WACC will be calculated based on the weighted costs of debt and equity, as approved in base distribution rate cases from time to time.

PROPERTY PURCHASES

Any property purchases are reflected in the revenue requirements on a yearly basis with

$$\text{Cost of Property} * \text{WACC} \tag{10.A.05}$$

and are not inflation adjusted over time

PROGRAM COST

Program costs (yearly and one-time) are added to the revenue requirements of the year they are incurred and include potentially applicable utility incentive amounts.

$$\text{Yearly Program Cost} * (1 + \text{State Specific Earnings Rate}) \tag{10.A.06}$$

Program costs are not inflation adjusted over time

O&M COST

O&M (or OpEx) costs to the company are a direct pass through to the revenue requirements, they do however increase by the inflation rate on a yearly basis.

ASSET REVENUE

If the NWA solution provides a revenue stream that can be set against its cost, the annual revenue will be subtracted from the annual O&M cost.

B. MACRS

MACRS 7 YEARS (363 - STORAGE BATTERY EQUIPMENT)

Table 6: 7 Year MARCS

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%

MACRS 5 YEARS (344/345 - SOLAR PANELS, INVERTERS, GENERATORS)

Table 7: 5 Year MARCS

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
20.00%	32.00%	19.20%	11.52%	11.52%	5.76%

MACRS 20 YEARS (344/345 - SOLAR PANELS, INVERTERS, GENERATORS)

Table 8: 20 Year MARCS

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%

C. ASSUMPTIONS BY ENTITY

The NWA Framework will incorporate entity-specific values, where appropriate, for inputs into the revenue requirement calculation including property tax expense, state income tax expense, capital structure, cost of debt, equity, and preferred stock, and Energy Efficiency performance incentive levels.

11. REVENUE ESTIMATION MODEL

As part of the NWA Framework, potential revenue streams which can be generated through DER resources can be considered.

A. REGIONAL NETWORK SERVICE (RNS) AND LOCAL NETWORK SERVICE (LNS)[15]:

The RNS Rate is the rate applicable to Regional Network Service to affect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

LNS is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

As part of the NWA Framework and Tool, the RNS and LNS values will <u>not</u> be considered as an input when evaluating NWAs only, due to the following considerations:

a. The total volume of RNS and LNS cost on the transmission system remains the same, any reduction of those costs at one specific utility will result in an uptake of cost with all other utilities. From a regulatory standpoint, this favoring of one customer base over another is in the eyes of the EDCs not conducive to achieving the most cost-effective solution for all ratepayers
b. The Framework and Tool base their cost benefit analysis on the impact on Revenue Requirements, both the LNS and RNS values cannot be realized as an impact on the Revenue Requirements for a specific solution, therefore should not be considered.
c. In the medium and long term, Eversource expects a large-scale uptake of storage on the ISO-NE System. With large quantities of flexible resources, it is to be expected that most, if not all utilities will optimize dispatch against LNS/RNS cost, effectively flattening peak loads. As a result, any benefit that might have been had in the early days will disappear overtime.
d. For BESS, dispatch is solely reserved for managing distribution grid constraints, as such resources need to be held at ready state and can therefore not be used to address these value streams.

B. ISO REGISTRATION MODEL[16][17][18]

DERs have several options for registering with the ISO New England. However, not all options are acceptable/feasible for DERs listed as NWAs as it significantly limits their ability to act on distribution grid needs. The following options are available.

a. **SOG:** A generating unit may register and participate in the wholesale market as a Settlement Only Generator if it has capability of less than five MW connected below transmission per OP-14. A SOG does not participate in the day ahead energy market, participated in the real time energy market but without submitting priced energy offers, thus not dispatched by operations and is not monitored in real time. An SOG can participate in the capacity market, in the regulation market as an alternative technology regulation resource, ATRR, and not in the reserve market.

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[15] https://www.iso-ne.com/static-assets/documents/2019/10/transmission_planning_improvements.pdf

[16] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op14/op14_rto_final.pdf

[17] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op18/op18_rto_final.pdf

[18] https://www.iso-ne.com/participate/support/glossary-acronyms/

b. **MG:** Modelled Generation is any generating unit participating in the wholesale market whose capability is greater than 5 MW connected at any voltage level or below 5 MW connected to transmission must register as a Modeled Generation. A MG may participate in the day ahead energy market (must if it has a capacity supply obligation from the capacity market), must make priced energy offers in the real time energy market, and have appropriate telemetry per OP-18 so operations can dispatch and monitor output. A MG can participate in the capacity, reserve and regulation markets provided the unit meets applicable technical requirements.

c. **LR:** A Load Reducer is any operating generating unit not registered as a generating unit to participate in the wholesale energy, reserves or regulation markets. A load reducer may participate in the regulation market as an ATRR.

Note: For a DER to be considered as an NWA, the EDC's NWA dispatch always takes precedent over the ISO's dispatch for two reasons:

a. The ISO has a larger pool of resources to draw upon with a statistical assumption of compliance allowing it to address issues with a level of non-response from assets whereas the EDC with its limited NWA resources behind a single constraint relies on the asset's participation.
b. Failure to comply with the EDC's NWA dispatch can result in a localized power system failure resulting in customer outages and the DER being offline for either one purpose.

The NWA Framework therefore applies the following considerations

a. In general, **for all NWA assets**, the preferred mode to register with the ISO is SOG or LR. While registration as MG provides more access to market value streams, it requires strict dispatch schedules and steep penalties for non-compliance of those schedules. With the primary objective of the asset being distribution system reliability and ISO and distribution system needs not always aligning, this would cause a conflict of interest with potentially critical amounts of penalties incurred as the distribution system dispatch would always take precedence. The associated risk with such a participation cannot be modeled precisely and therefore does <u>not</u> lend itself as a reliable revenue stream.
b. In the event that storage is used as a grid resource and while owned by an EDC cannot participate in energy markets, it could be treated as a load reducer. In this case, the Framework looks only at the energy losses in the charging and discharging cycle as the battery would charge at retail and discharge at retail, not being allowed to make any revenue. (all SOG registered storage assets charge and discharge at wholesale cost)

Note: This limits the asset size to 5MW as any assets above this threshold are required to be a MG

C. ISO MARKET PARTICIPATION

In order to estimate any applicable revenue streams from different NWA resources which can be taken into consideration for offsetting revenue requirements to the customer, the NWA Framework assumes the following Table 9 highlighting how each resource type, depending on its registration model, will can participate.

Table 9: Applicable Energy Market Revenue Models by Type of DER

NWA	ISO Registration Model	Day Ahead Energy Markets	Real Time Energy Markets	Forward Capacity Markets
Large Scale Solar DG	SOG	NA	Applies	Applies
	MG	Applies	Applies	Applies
	LR	NA	NA	NA
Large Scale Storage	SOG	NA	Applies	Applies
	MG	Applies	Applies	Applies
	LR	NA	NA	NA
Energy Efficiency	on peak demand	NA	NA	Applies
	seasonal peak demand	NA	NA	Applies
Fuel Cell & CHP	SOG	NA	Applies	Applies
	MG	Applies	Applies	Applies
	LR	NA	NA	NA

Note: Due to limitations on the dispatch of NWA contracted DER, MG is not being considered.

D. ISO MARKET ASSUMPTIONS

The following Chapter provides a brief overview of the markets assumed accessible by the NWA Framework for DERs (excludes markets accessible through MG market participation)

REAL-TIME AND DAY AHEAD MARKET (WHOLESALE ENERGY)

The NWA Framework assumes a levelized wholesale energy price for all transactions and calculations over the financial planning horizon including annual inflation.

For simplicity reasons, the NWA Framework bundles the Real-Time and Day-Ahead Energy Markets into a single wholesale energy value for both MG and SOG registered DERs.

The NWA Framework defaults the levelized wholesale energy price to $40\,\frac{\$}{\mathrm{MWh}}$

FORWARD CAPACITY MARKET (FCM)[19]

Due to various policy and market drivers, future supply and demand projections in New England and associated capacity market price formation is continuously evolving. We therefore believe using any forward projection of capacity prices provides a false sense of precision. But for purposes of accounting for some capacity market value, the NWA Framework applies the last FCM clearing price of $2.61 per kW-mo as a forward projection, subject to inflation.

E. DER REVENUE TIMELINES

As outlined early on, the NWA Framework requires DERs participating as NWA's to be under the EDC's dispatch control to ensure reliable operations at any point in time, if they are not EDC owned. During the duration of the NWA contract from the time of the NWA Solution goes live until the deployment of the traditional solution at the end of the deferral horizon, any NWA DERs are assumed to be under EDC dispatch. As a result, they might lose market revenues. This will specifically be the case with storage systems. However, especially for storage assets, DERs can be freed from this responsibility at the point the deferral of the traditional investment is completed. Once the traditional upgrade is in place to no further require NWA services, the battery could be utilized for bulk services.

[19] https://www.iso-ne.com/static-assets/documents/2021/02/20210211_pr_fca15_initial_results.pdf

F. DER REVENUE

The NWA Framework allows consideration of multiple NWA revenue streams. Even with several of the NWA solutions modeled as utility owned and operated, it is assumed that these resources can produce a revenue stream through e.g. generation of electric energy.

SOLAR PV

The NWA Framework allows for the following revenue streams from solar PV resources:

a. **Wholesale Energy Revenue**: Applicable to SOG registered solar plants as well during and after the NWA dispatch, revenue from the wholesale energy market is calculated in the tool using the assumption of an annual generation of

$$\int \left[\varepsilon * \frac{I_{\text{Clear Sky Irr}}(t)}{1000\frac{\text{W}}{\text{m}^2}} * \lim_{\text{P}_{\substack{\text{max}\\ \text{AC}}}} \left(\text{P}_{\substack{\text{max}\\ \text{DC}}} \right) \right] \text{dt} \qquad \text{11.E.01}$$

Where kW_{DC} represents the installed DC Panel Power. The Framework assumes a uniform reduction of solar irradiance by ε over the entire year

b. **Net Metering**: Similar to wholesale revenue, the annual generation is calculated and applied to retail prices for net metered assets, which are registered as LR.

c. **State Sponsored Generation Credits**: Applicable depending on the state. To account for government funding of generation sites, the NWA Framework accounts for the presence of a generation credit in $\frac{\$}{\text{kWh}}$. The generation credit is applied to the revenue estimation as a cap for what PV solar resources can earn on their energy. Therefore, the additional value generated equals the difference of the generation credit and what was already earned through wholesale energy market revenue.

$$\min_{=0}\left(\$_{\text{Gen Credit}} - \$_{\text{Wholesale Energy}}\right) \qquad \text{11.E.02}$$

d. **Forward Capacity Market Revenue**: Applicable to SOG registered solar plants. Revenue from the forward capacity market is calculated using the default assumption that solar is issued a capacity credit of 18% of the installed AC power.

Note: BTM solar is <u>not</u> attributed any revenue streams in the NWA Framework as the approach provides for the EDC paying a kWh-based subsidy to residents to install solar. Therefore, any revenue streams from the solar installation end up with the customer, and the per kWh payments remain directly impactful on the EDC's revenue requirements.

ENERGY EFFICIENCY[20]

The NWA Framework provides an FCM revenue for Energy Efficiency. Hereby, an Energy Efficiency measure that has been completed can generate FCM revenue for 1 to 25 years (averaging 8 years, given the current measure mix).

a. **Forward Capacity Market Revenue:** Energy Efficiency measures can be registered with the FCM while providing a capacity value for two windows throughout a year
    - April to November (Summer)
    - December to March (Winter)

    The capacity values accounted for in each window are based on one of two methods of calculation
    - On-Peak:

[20] https://www.iso-ne.com/markets-operations/markets/demand-resources/about

i. To calculate the summer on-peak value, the energy efficiency capacity impact on an hourly basis for all non-holiday weekdays from June to August between 1 and 5 pm are added up and divided by the total number of hours.

ii. To calculate the winter on-peak value, the energy efficiency capacity impact on an hourly basis for all non-holiday weekdays from December to January between 5 and 7pm are added up and divided by the total number of hours.

- Seasonal Peak:

i. To calculate the summer seasonal peak value, the energy efficiency capacity impact is assessed on non-holiday weekdays in hours when the real-time system hourly load is equal to or greater than 90% of the system peak-load forecast during June – August timeframe.

ii. To calculate the winter seasonal peak value, the energy efficiency capacity impact is assessed on non-holiday weekdays in hours when the real-time system hourly load is equal to or greater than 90% of the system peak-load forecast during December – January timeframe.

DEMAND RESPONSE

Demand Response is not considered for ISO based revenue streams in the NWA Framework.

CONSERVATION VOLTAGE REDUCTION

Conservation Voltage Reduction is not considered for ISO based revenue streams in the NWA Framework.

BATTERY STORAGE

a. **Wholesale Energy Revenue**:

a. **During NWA Dispatch**

i. **LR:** An LR Storage charges and discharges at retail rate, which is constant, and can therefore not generate any revenue.

ii. **SOG:** An SOG Storage charges and discharges at wholesale energy cost. Since the Framework assumes a levelized wholesale energy cost, no value is yielded. Therefore, the Framework assumes an arbitrage value which is defaulted to 40$/MWh. The number of yearly constraint events yields to amount of energy discharged.

$$\sum_{\text{Events/year}} t * Q_{\text{Discharged}} * \frac{\$_{\text{Arbitrage}}}{\text{MWh}} \qquad 11.E.03$$

b. **After NWA Dispatch** Applicable SOG, battery storage systems charge at wholesale energy rates, and discharge at wholesale energy rates. Using 11.E.03 the tool provides inputs for assumed annual cycles after the NWA dispatch contract is completed with a default value of 365.

b. **State Sponsored Generation Credits**: Applicable depending on state. To account for government funding of storage sites, the NWA Framework accounts for the presence of a generation credit in $\frac{\$}{\text{kWh}}$. The generation credit is applied to the revenue estimation as a cap for what resources can earn on their energy. Therefore, the additional value generated equals the difference of the generation credit and what was already earned through wholesale energy market revenue.

$$\min_{=0}\left(\$_{\text{Gen Credit}} - \$_{\text{Energy Revenue}}\right) \qquad 11.E.04$$

c. **Forward Capacity Market Revenue**: Applicable for SOG resources after the completion of an NWA contract.

Note: BTM battery installations managed through a utility program will not be considered for additional ISO based revenue streams as any revenue from the assets stays with the customer and the EDC is not acting as a virtual power plant (VPP) but rather has contracts only for the NWA dispatch requirements.

Note: If the Battery is operated as a LR it cannot participate in wholesale energy markets and therefore will charge and discharge at retail rates making it impossible to yield an arbitrage, as those rates are not time dependent. Cost of operating the battery therefore is defined by the energy losses and the retail cost of energy.

FUEL CELL & CHP

As Fuel Cells and CHP are part of targeted energy efficiency programs, any revenue generated through heat or electric generation flows directly to the customer.

EMERGANCY GENERATION

a. **Wholesale Energy Revenue**: The only revenue option assumed for emergency generators is the wholesale value of the energy produced during dispatch. Hence, the total assumed revenue from emergency generation equals

$$\sum_{\mathrm{Events/year}} t * P_{\mathrm{installed}} * \frac{\$_{\mathrm{wholesale}}}{\mathrm{MWh}} \quad \text{11.E.05}$$