Operational Impact of Extreme Weather Events

Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results

Operational Impact of Extreme Weather Events – Energy Adequacy Study

- ISO collaborated with EPRI to conduct a probabilistic energy adequacy study for the New England region in the operational time frame under extreme weather events
- Study results have informed the region on energy shortfall risks over the next decade
  - These results are expected to inform the development of a regional energy shortfall threshold (REST) in 2024
- This study has established a framework for risk analysis under extreme weather events and ISO expects that this framework will be essential as climate projections are refined and the resource mix evolves

Operational Impact of Extreme Weather Events – Energy Adequacy Study, cont.

- There are three major steps in this framework:
  - Step 1: Weather Modeling (performed by EPRI)
  - Step 2: Risk Screening Model Development and Scenario Generation (performed by EPRI)
  - Step 3: Energy Assessments (performed by ISO)
- This final report summarizes the data and methodologies used in the first two steps, presents results of Step 3 energy assessments completed for winter and summer 2027 and 2032 events and reviews sensitivity analysis performed for the worst case 2032 winter event

Index of Key Findings

- Weather modeling, incorporating climate change projections, identified that New England summer and winter minimum temperatures are warming faster than maximum temperatures
- The top 10 events from the Risk Screening Model indicated primarily winter system risk for both study years
- The worst energy shortfall of the primary scenarios, was seen under the January 22, 1961 weather event for both 2027 and 2032 in the scenario with no New England Clean Energy Connect (NECEC), low LNG, low oil, low imports, and EMT in service
  - Similar energy adequacy risk was found with and without EMT in service. The primary modelling difference in those scenarios was the maximum daily LNG injection rate
  - Risks are mitigated by incremental imports from NECEC
- No energy shortfall was observed for both 2027 and 2032 summer events
- Stakeholder-informed sensitivities explore modified assumptions on the January 22, 1961 weather event
- Key takeaways of 2027 and 2032 studies highlight the dynamic nature of the region’s energy shortfall risk and the importance of the PEAT framework as the system continues to evolve

STEP 1 – WEATHER MODELING

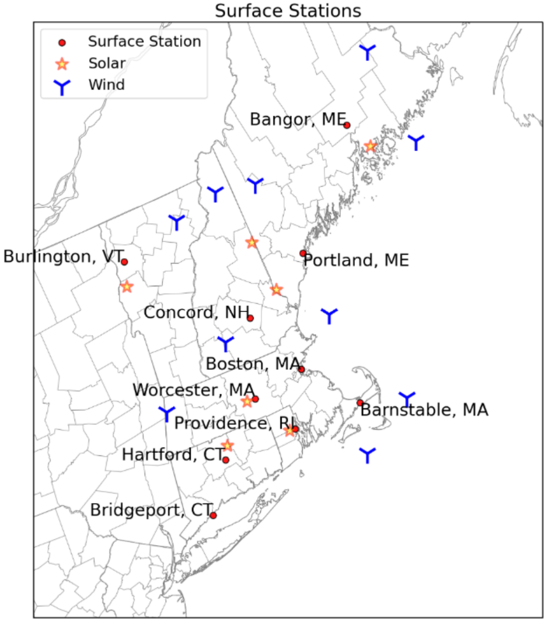
Overview of Step 1 Weather Modeling

- The objectives of this step were to identify 21-day weather events of interest using statistical analysis and to develop hourly profiles of weather variables for future periods of study
- This analysis includes the acquisition and interpretation of locationally-specific climate data
  - This data was used to characterize trends, including uncertainty, in the mean and extremes for different weather variables of interest
- As part of Step 1, EPRI performed a historical weather (1950 – 2021) review of the New England region which provided context to ISO and stakeholders related to historical extremes and trends
- EPRI used five global climate models spanning a range of climate sensitivities and two climate scenarios to project changes to historical weather
- Hourly profiles of weather variables produced via the climate modeling techniques were then used to develop hourly demand forecasts and energy output profiles for wind and solar resources for the periods being studied

STEP 1: NEW ENGLAND HISTORICAL WEATHER REVIEW

New England Historical Weather Review
1950-2021

- 10 surface stations for weather data collection and analysis were selected
  - 6 onshore wind, 4 offshore wind and 7 solar were also identified to be used in development of wind and solar resource profiles in later stages of this project
- Surface station locations (all airports):
  - Hartford, CT; Bridgeport, CT; Providence, RI; Worcester, MA; Barnstable, MA; Boston, MA; Burlington, VT; Concord, NH; Bangor, ME; and Portland, ME



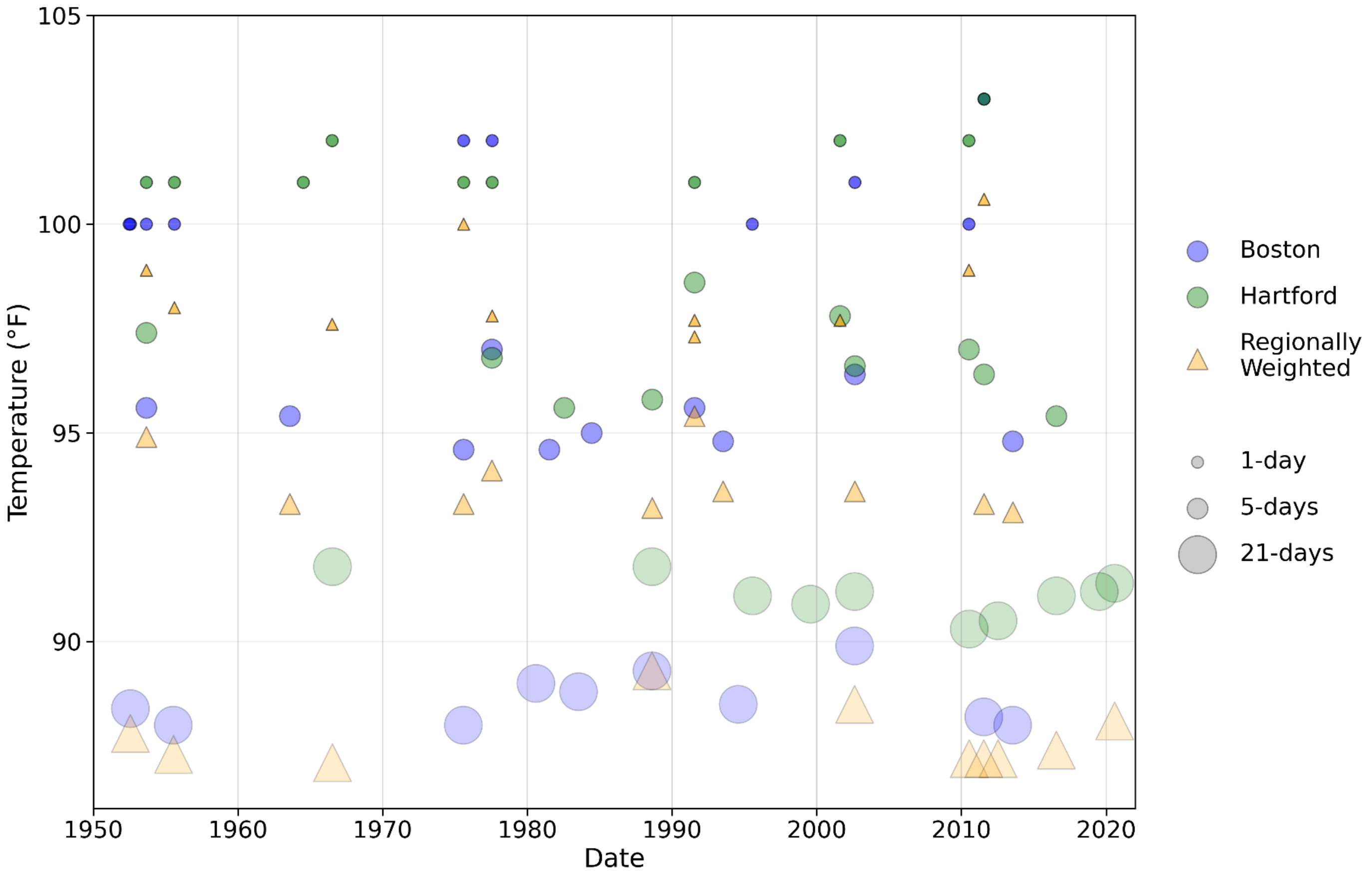
- Weather variables of interest were selected
  - Temperature (units: °F)
  - Precipitation, rain and snow (units: inches)
  - Dewpoint (units: °F)
  - Wind speed at 10m & 100m (units: m/s)
  - Wind direction
  - Downward shortwave radiation (units: w/m^2)
- Weather variable data was sourced from the Midwestern Regional Climate Center's Cli-MATE data portal

New England Historical Weather Review, cont.

1950-2021

- In order to provide historical weather context, using the historical weather variable data gathered for each of the 10 surface station locations, EPRI developed comprehensive characterizations of historical temperatures, including extremes, variability, and trends
- This section of the report is centered primarily on Hartford, CT and Boston, MA to focus the discussion on larger population centers in New England
  - Additional figures of historical weather review for other cities are included in the Appendix of *March 15, 2022 NEPOOL Reliability Committee meeting*
  - The figures in this section of the report depict 1950-2020 historical weather data although the analysis performed in Step 1 utilizes data spanning 1950 to 2021
- Thresholds for "extreme" heat and cold used in Step 1 were developed based on a review of the historical data and available literature; these thresholds were not used to define "extreme" in Step 2

Top 10 Hottest – Boston, MA and Hartford, CT (*Daily Max °F*)

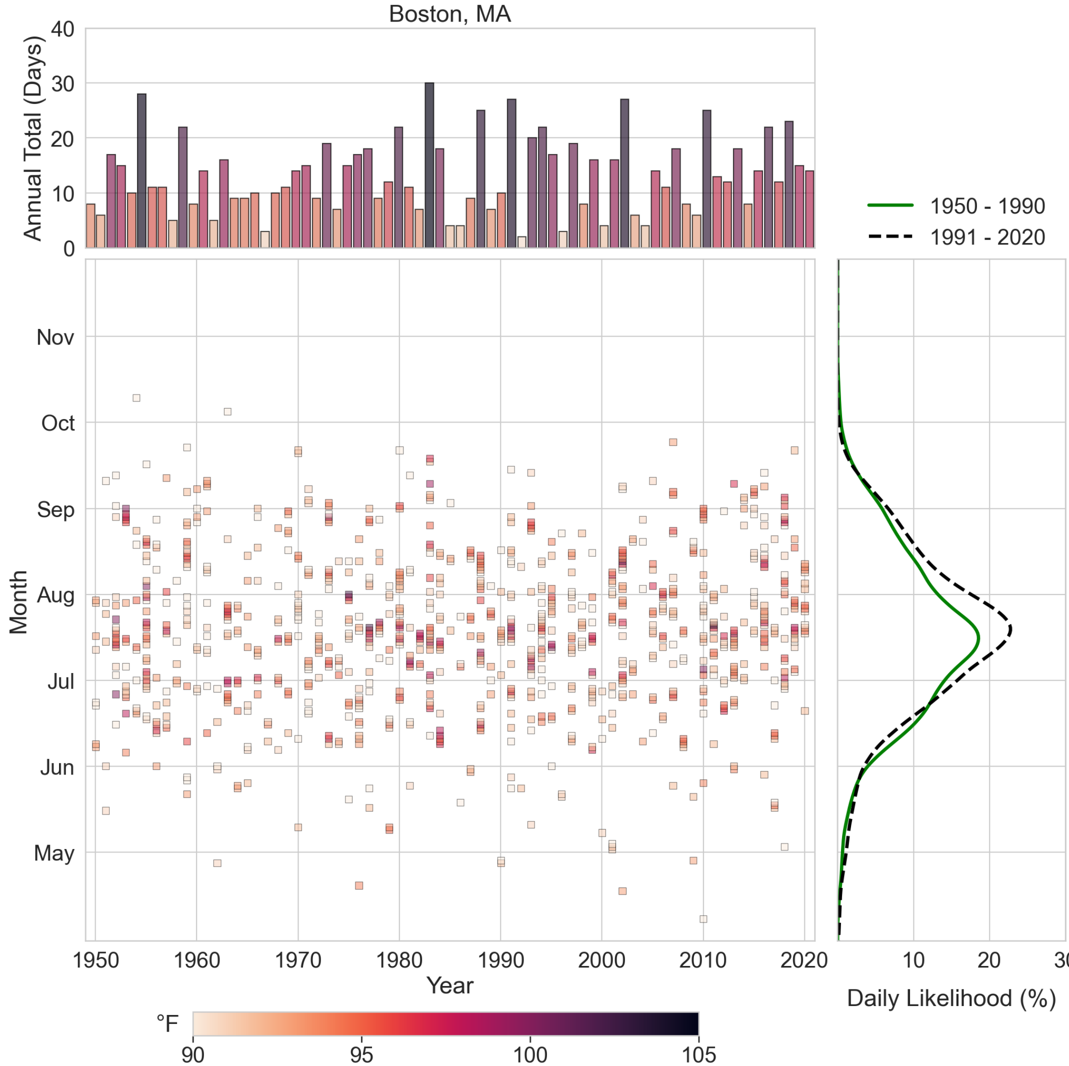


Key Points:

- 9 of the top 10 hottest 21-day events in Hartford have occurred since 1988
- Boston and Hartford's hottest days have occurred in the last decade

Extreme Heat Days >= 90°F

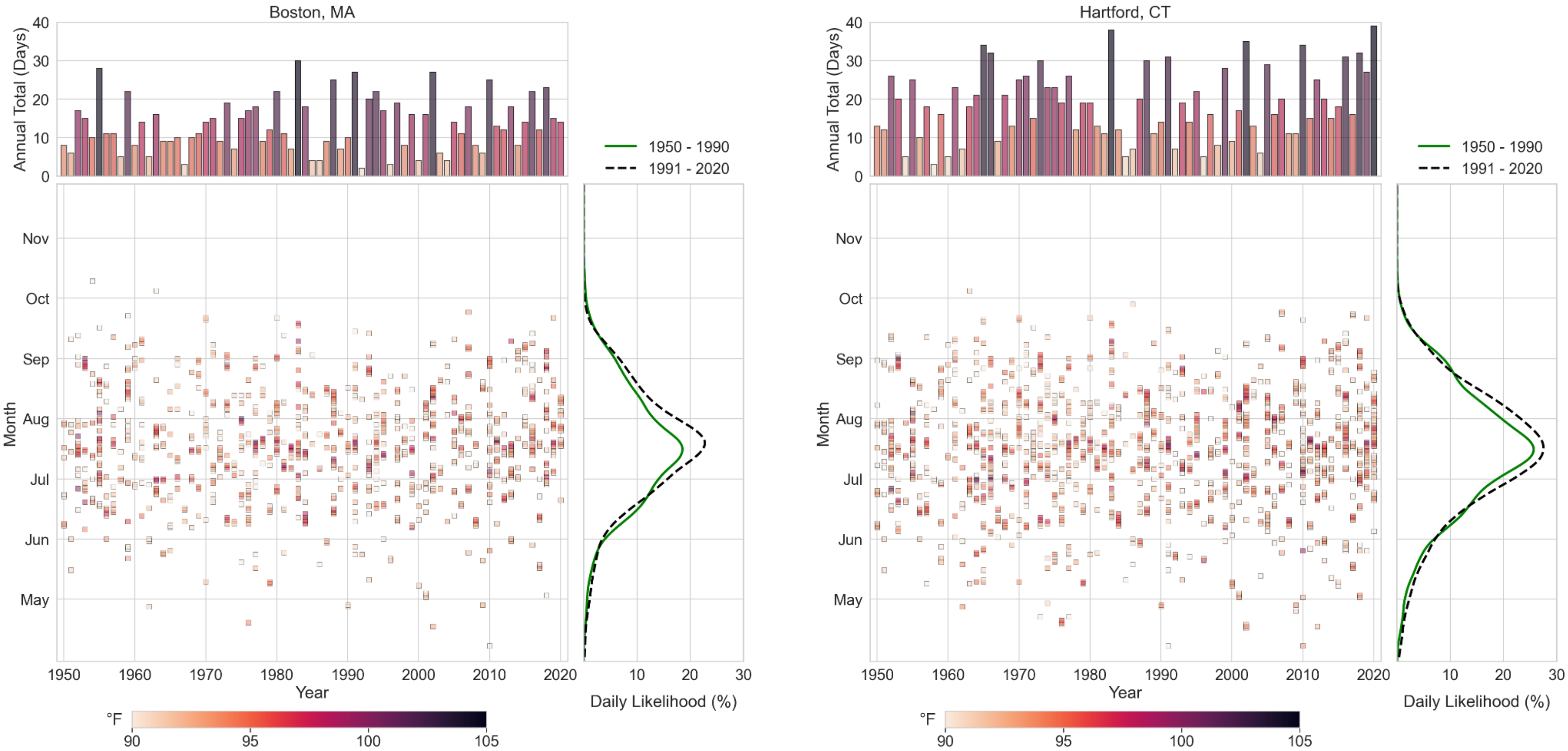
Boston, MA



Overview

- This figure shows the frequency of extreme heat (top), the seasonality of extreme heat (main), and the likelihood of extreme heat by day of the year (right) from 1950 – 2020
- **Extreme heat in this case is defined as a daily maximum temperature greater than or equal to 90°F**
- Note that 1991 – 2020 is the new climate normal period as defined by the National Oceanic and Atmospheric Administration (NOAA)

Extreme Heat Comparison
(*Boston, MA vs Hartford, CT)*



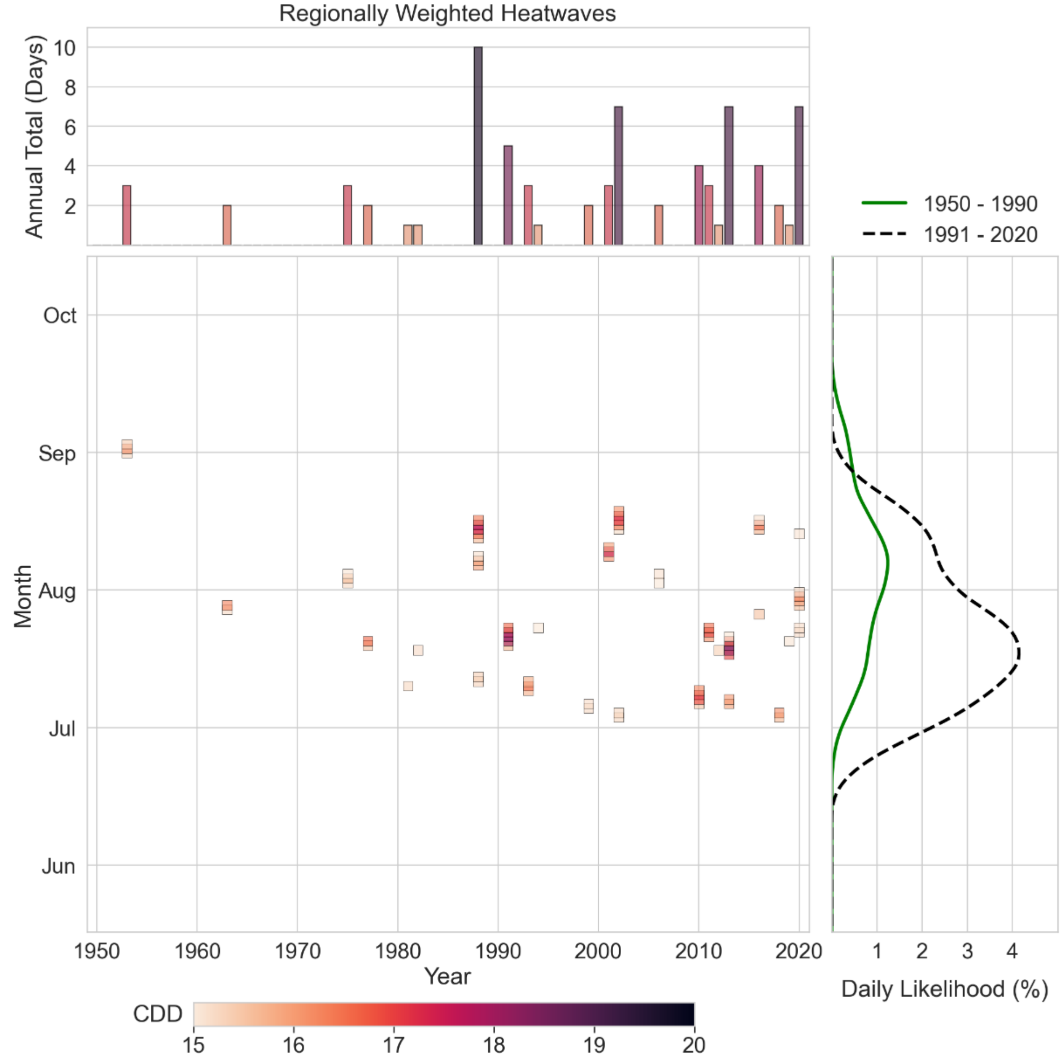
Key Points: Extreme heat has increased in frequency in recent decades

- The seasonality of extreme heat has remained consistent with a peak in late July
- Year-to-year variability in the total number of extreme heat days has increased

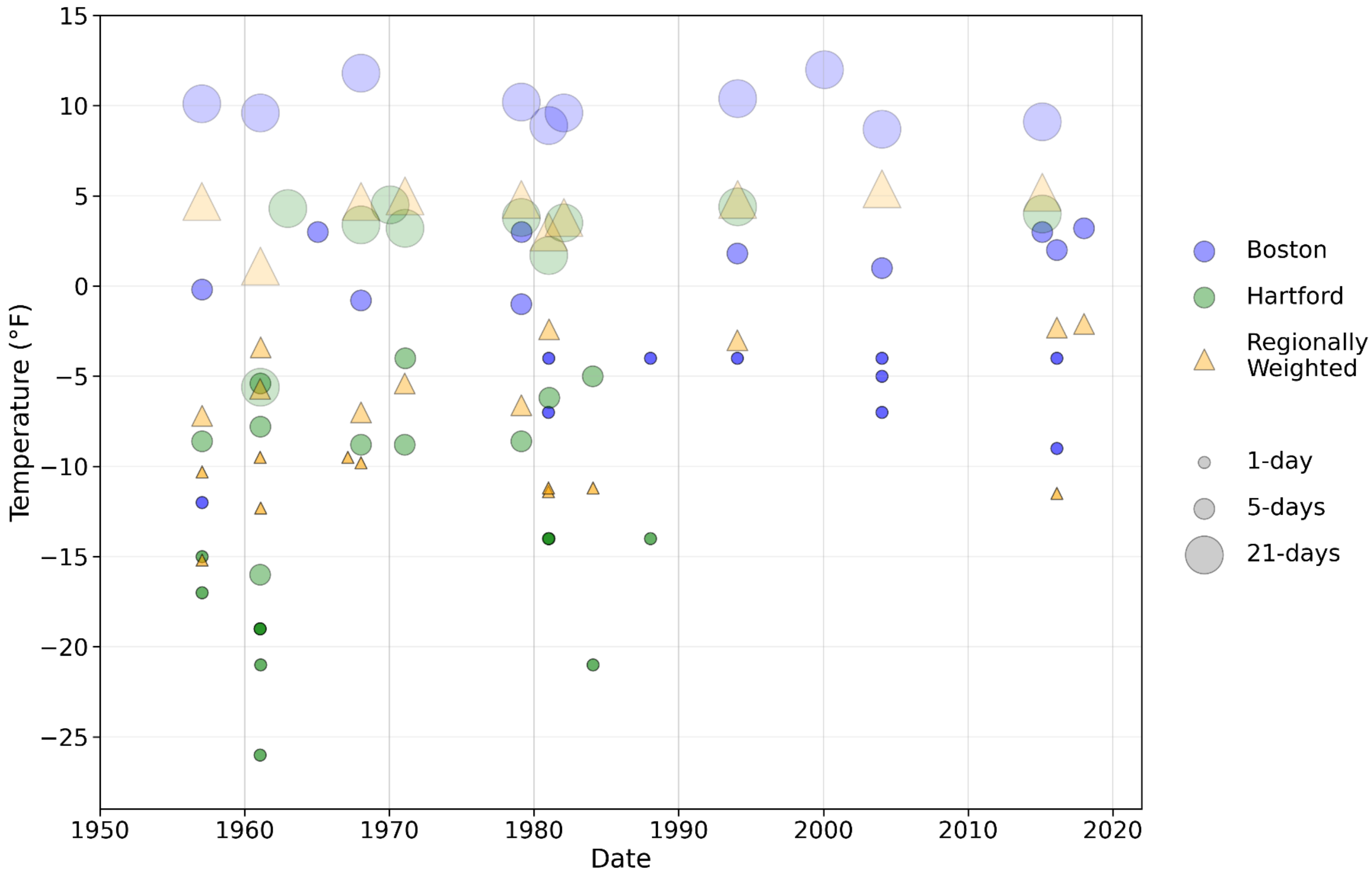
Extreme Heat Days (CDD >= 15)
Regionally Weighted

Overview
- This figure shows regionally weighted extreme heat (top), the seasonality of extreme heat (main), and the likelihood of extreme heat by day of the year (right) from 1950 – 2020
- This figure shows the frequency of extreme heat in the context of cooling degree days (CDDs)
    - **Extreme heat in this case is defined as a daily CDD >= 15°F**
    - CDDs are based on a 65°F threshold for daily mean temperature

Key Point:
- Region-wide extreme heat is 4 times as likely to occur now as it was from 1950 – 1990



Top 10 Coldest – Boston, MA and Hartford, CT (*Daily Min °F*)



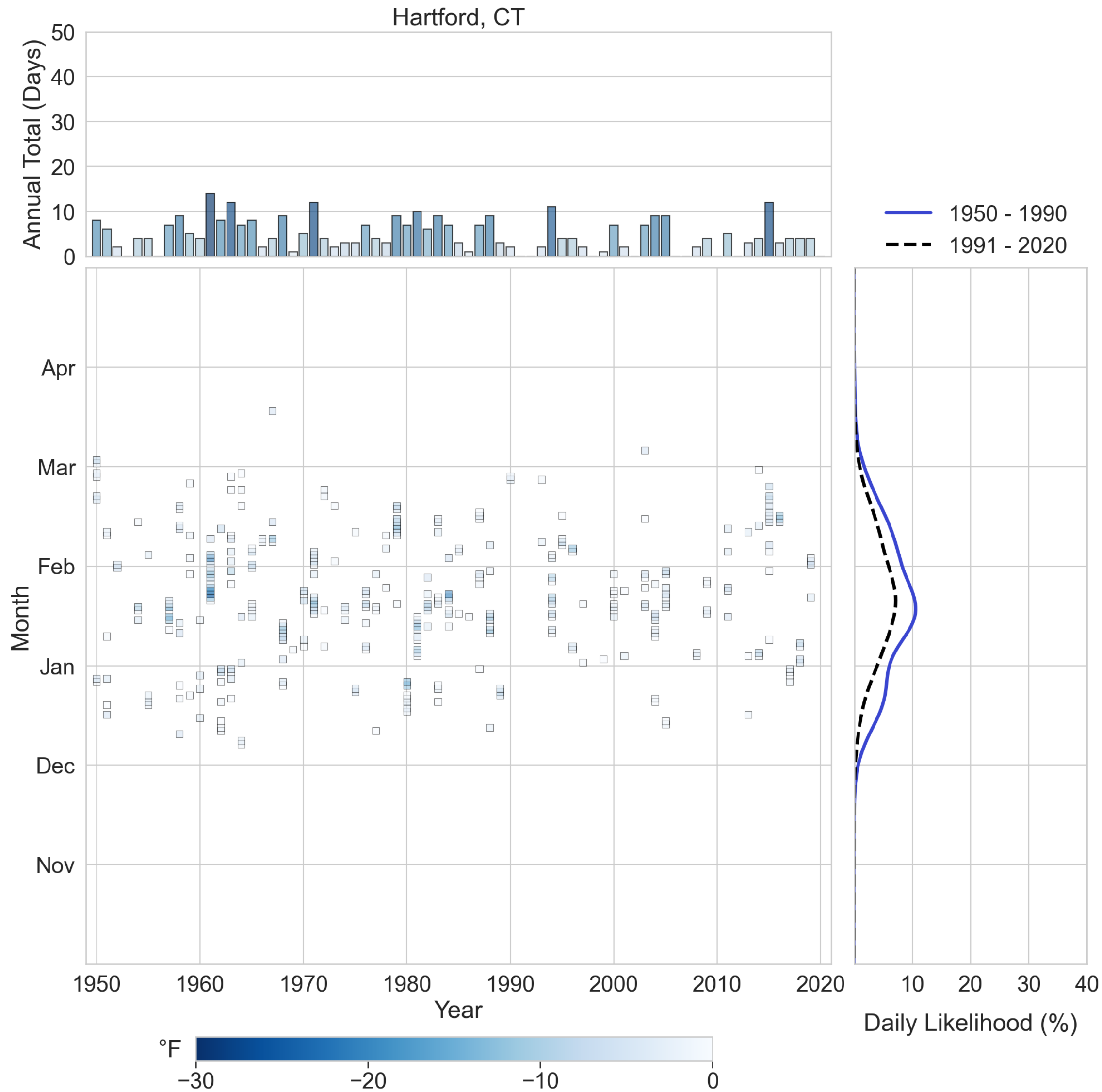
<u>Key Point</u>: The top 10 coldest 1, 5, and 21-day events for Boston are relatively equally distributed over the past 70 years, but the top 10 events in Hartford and the region more commonly occurred between 1950 – 1980

Extreme Cold Days <= 0°F

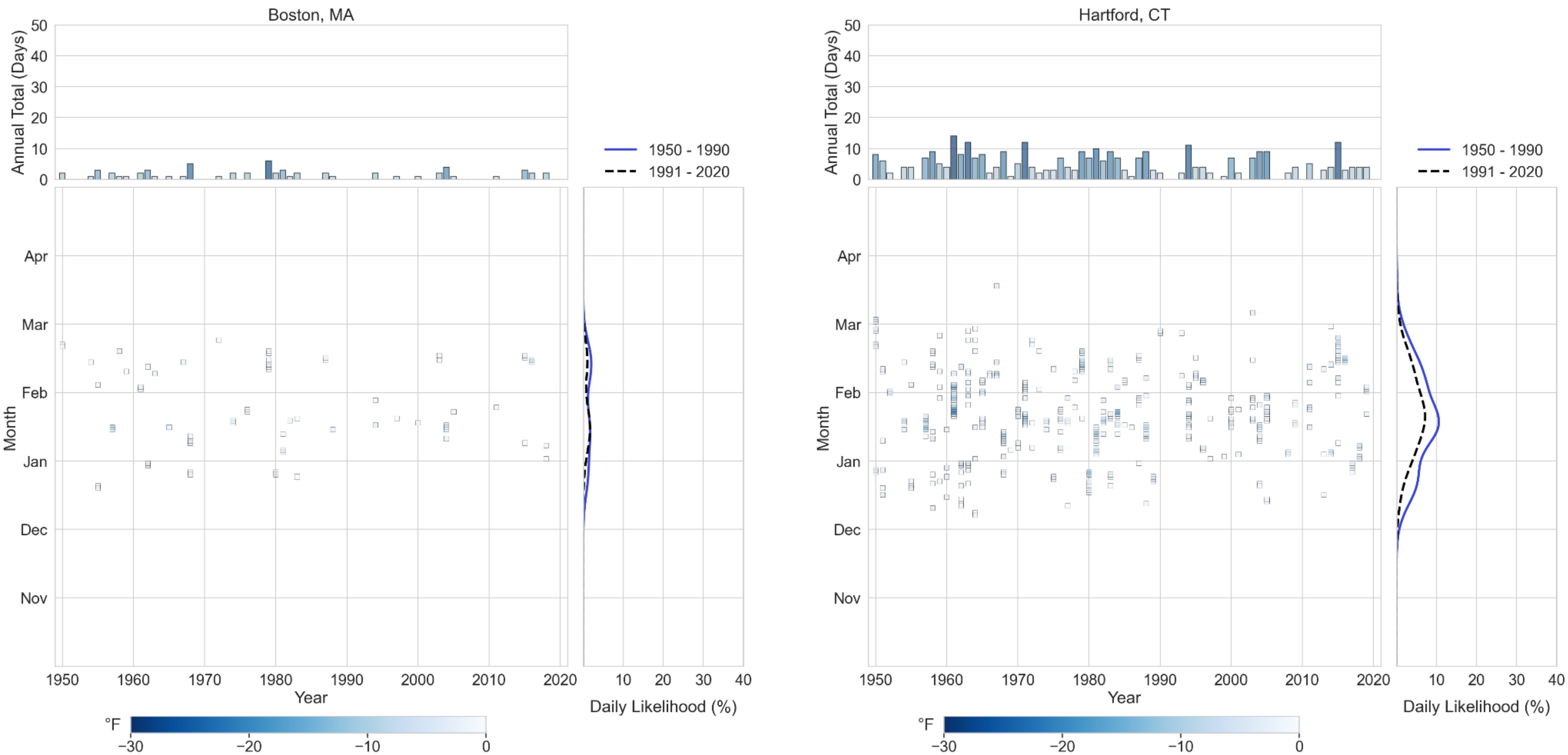
Hartford, CT

Overview

- This figure shows the frequency of extreme cold (top), the seasonality of extreme cold (main), and the likelihood of extreme cold by day of the year (right) from 1950 – 1990 and 1991 - 2020
- **Extreme cold in this case is defined as a daily minimum temperature equal to or below 0°F**



Extreme Cold Comparison
(*Boston, MA vs Hartford, CT)*



<u>Key Points</u>: Extreme cold is decreasing in frequency

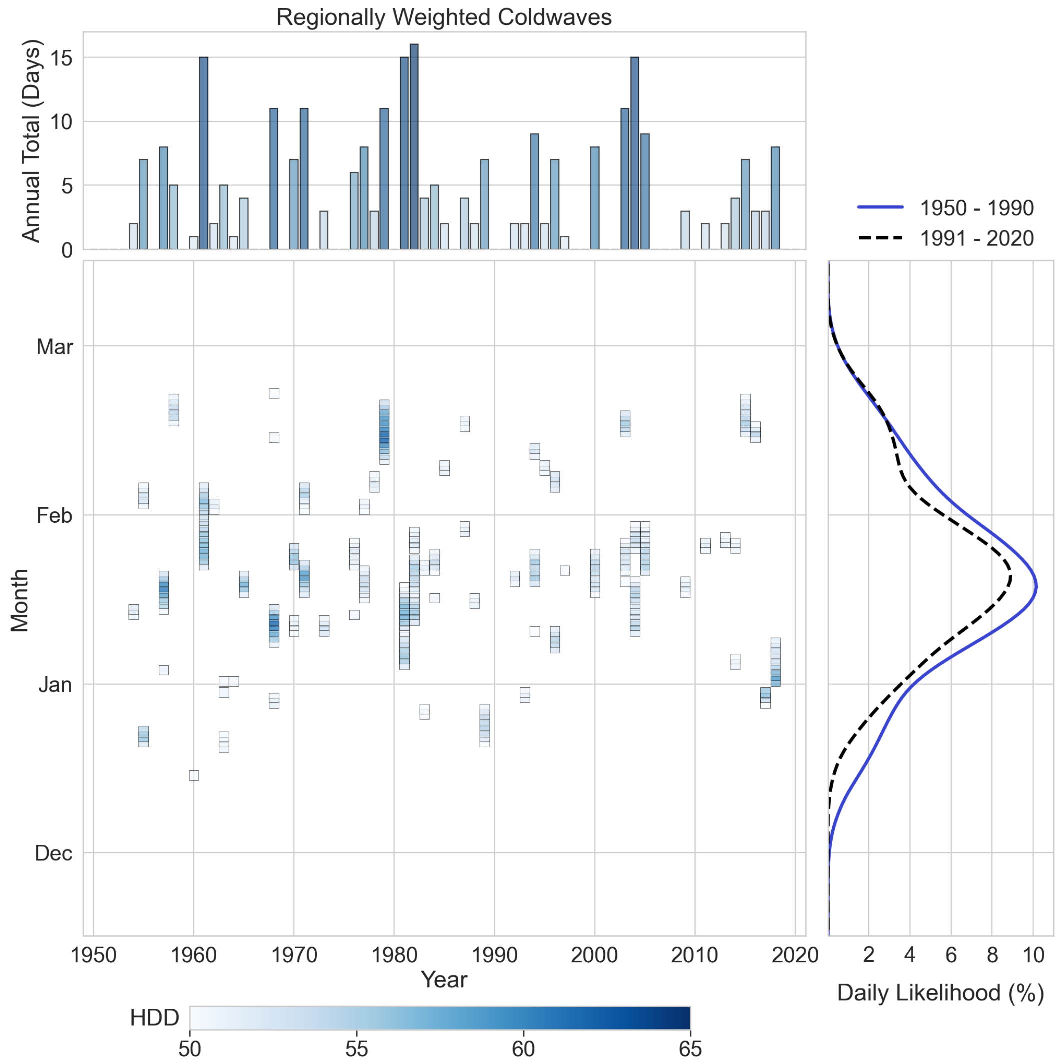
- Boston's proximity to the water helps to moderate extreme cold
- Historically, mid-January is the peak for extreme cold temperatures
- Boston and Hartford have fewer extreme cold days than the other 8 cities

Extreme Cold Days (HDDs >= 50)

Regionally Weighted

Overview

- This figure shows regionally weighted extreme cold (top), the seasonality of extreme cold (main), and the likelihood of extreme cold by day of the year (right) from 1950 – 2020
- This figure shows the frequency of extreme cold in the context of heating degree days (HDDs)
  - **Extreme cold in this case is defined as a daily HDD >= 50°F**
  - HDDs are based on a 65°F threshold for daily mean temperature



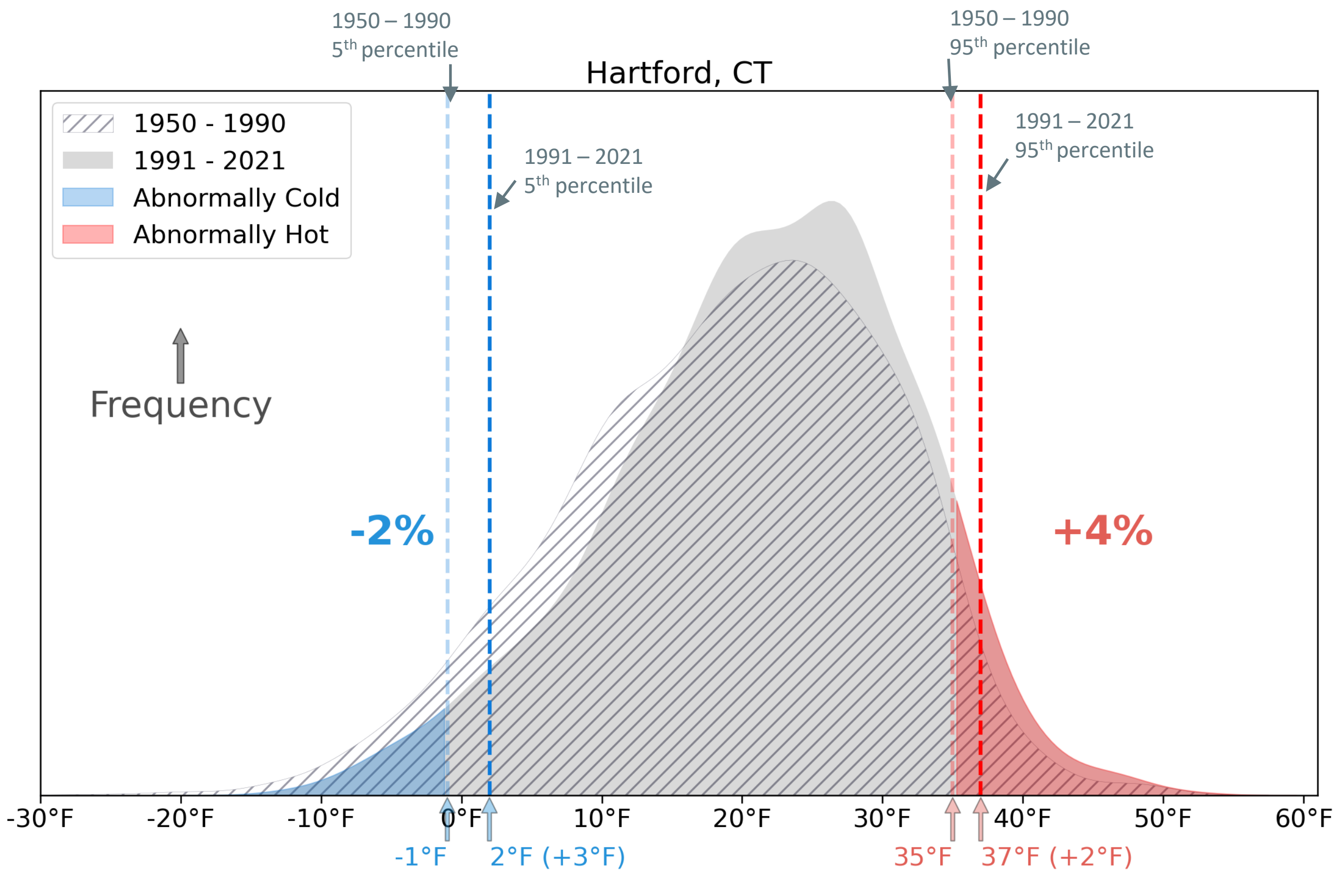
Key Point:

- While extreme cold has become less frequent across the region it can still occur, even in a warming climate

Temperature Distribution
Winter Daily High – Hartford, CT

Overview

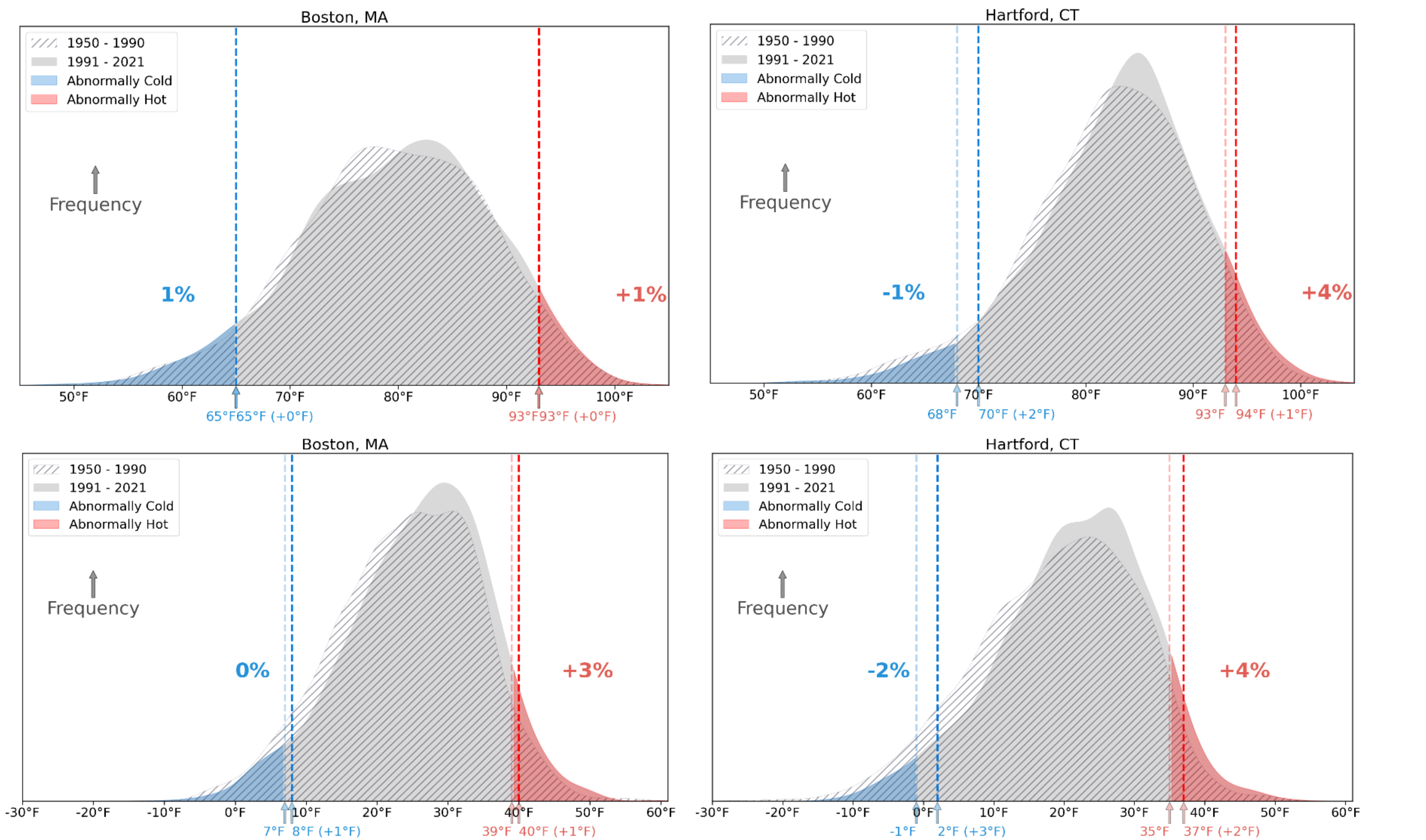
- This figure shows the changing distribution of temperatures from 1950 - 2020
- Changes in extremes (5th and 95th percentiles) are highlighted in blue (5th) and red (95th) shading
- Percentiles are defined by the season
- Winter includes the months of December – February



Temperature Distribution (*Boston, MA vs Hartford, CT)*

Summer High

Winter Low



<u>Key Points:</u>

- Summer high temperatures have increased across the region
- Winter temperatures have generally increased more than summer temperatures with much fewer days being below the 5th percentile from 1991 – 2020 compared to 1950 – 1990

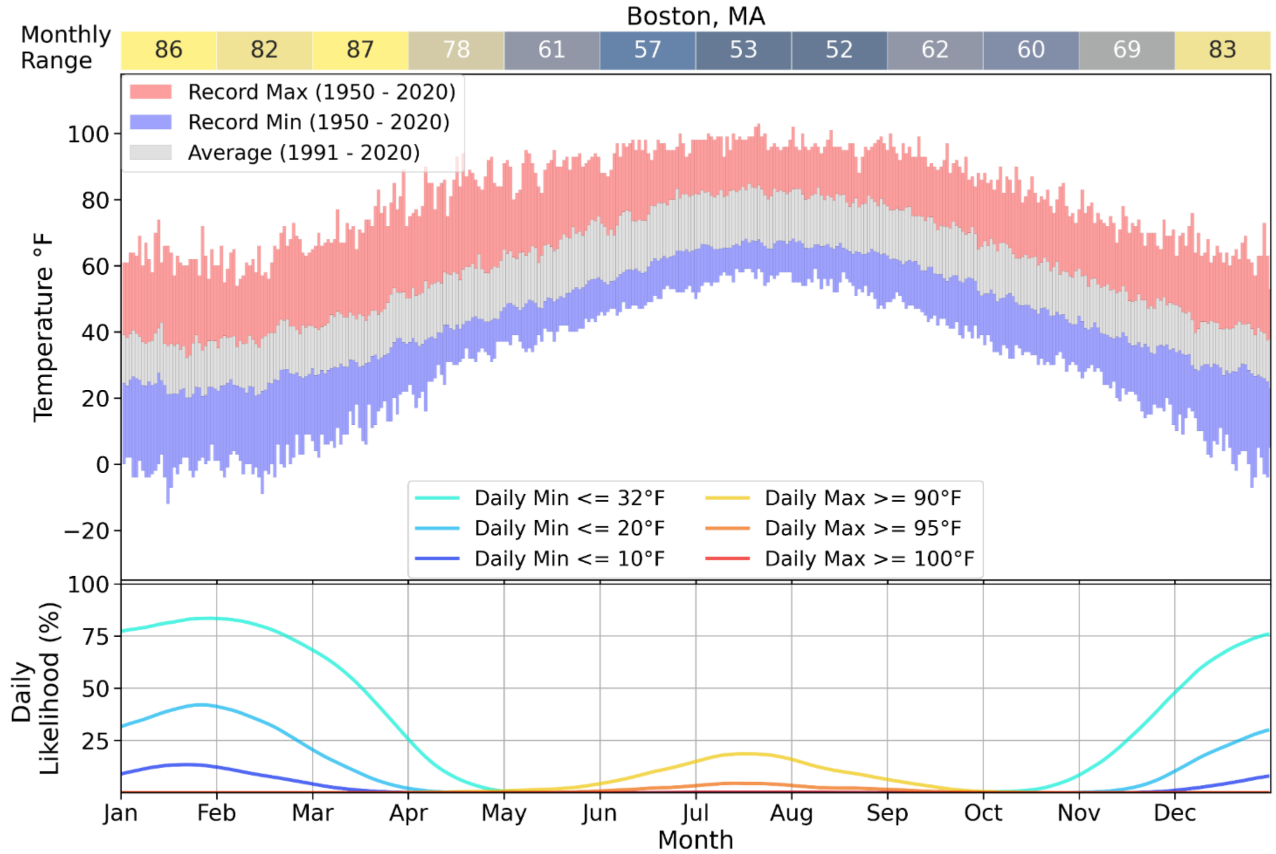
<u>Note</u>: Scale of x-axis changes from summer (45°F to 100°F) to winter (-30°F to 60°F), compressing the variability of winter temperatures.

Historical Temperature Climatology

Boston, MA

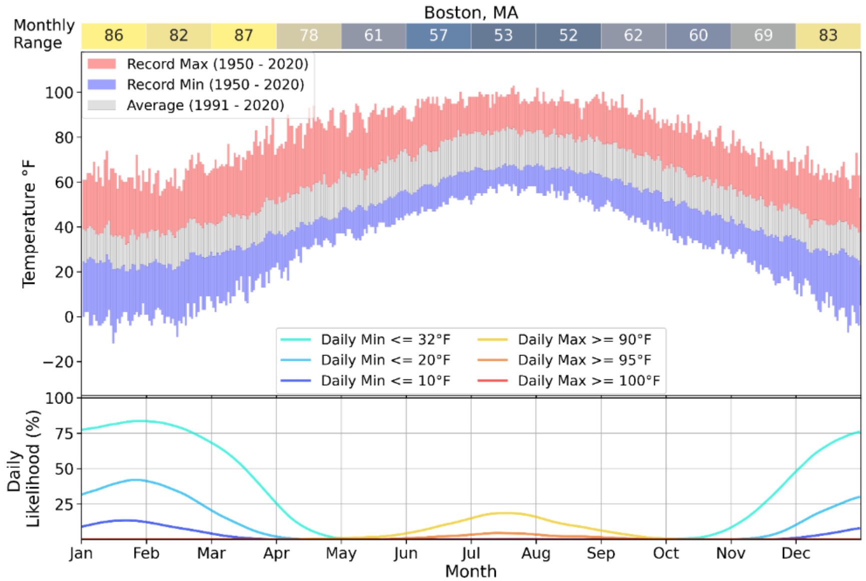
Overview

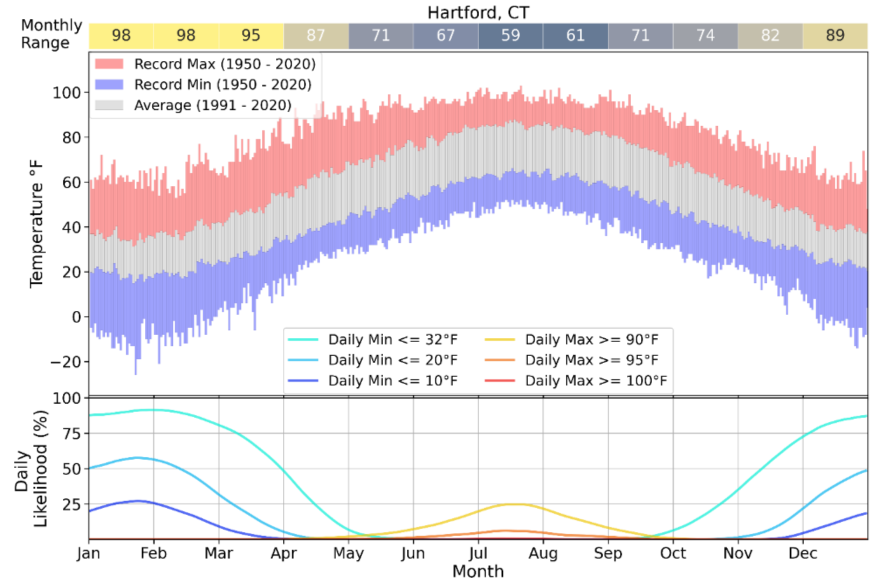
- Temperature variability (top)
    - Shows the historical monthly temperature range (record max – record min)
- Temperature seasonality (main)
    - Blue bars show average temperature range for every day of the year (daily max – daily min)
- Historical extremes (main)
    - Grey bars show historical range for every day of the year (record max – record min)
- Likelihood of exceeding temperature thresholds for every day of the year (bottom)
    - Based on entire period of record (1950 – 2020)



Historical Temperature Climatology

Boston, MA vs Hartford, CT

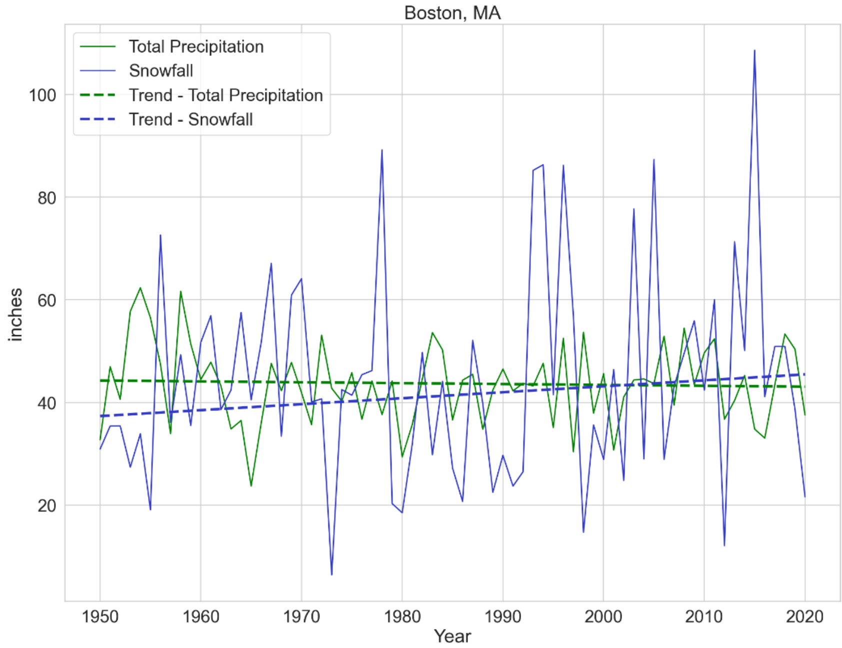


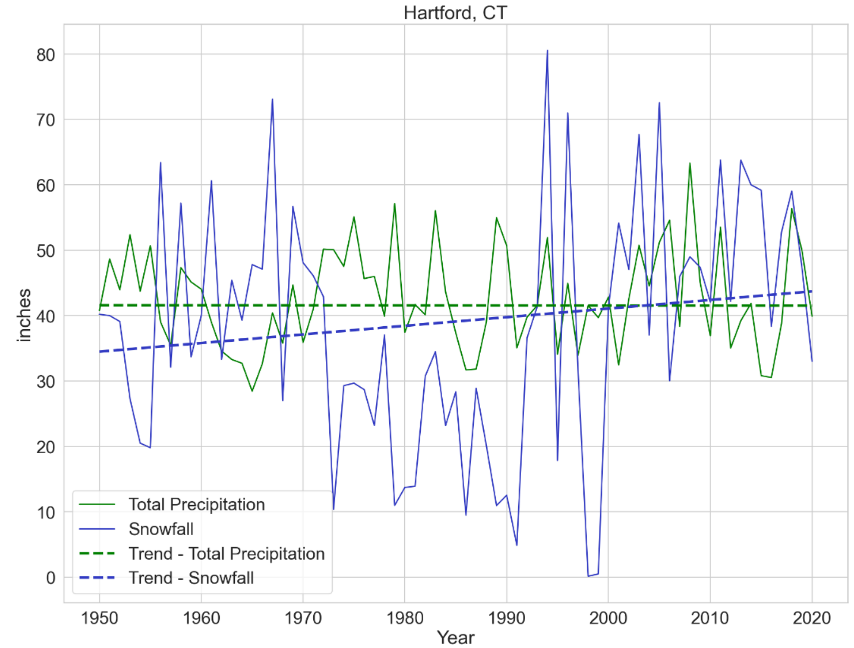


<u>Key Points:</u>

- Temperature variability is largest during winter
  - Hartford, CT has a larger variability than Boston, MA
- Diurnal temperature range is larger during summer than winter
- The likelihood of exceeding extreme heat thresholds during summer is much lower than the likelihood of exceeding extreme cold thresholds during winter

Precipitation Comparison
Boston, MA vs Hartford, CT





<u>Overview</u>

- These figures show the annual total precipitation (green line) as well as the annual total snowfall (blue line). *Note: precipitation includes rainfall and snowfall, but snowfall is converted to a liquid water equivalent.*
- Annual totals are calculated based on the calendar year (January – December)

<u>Key Points:</u>

- Annual precipitation totals have not changed for Hartford or Boston
- Snowfall has increased in both Hartford and Boston, though the snowfall trend in Boston is heavily influenced by 2015

New England Historical Weather Review
Key Takeaways

- Based on a review of historical weather data for the 10 locations in New England and the thresholds identified for extreme heat and cold:
  - Extreme heat has increased in frequency and extreme cold has decreased in frequency
    - When compared to 1950 – 1990, the frequency of extreme heat has increased by as much as 8% and the frequency of extreme cold has decreased by as much as 10% during the most recent 30-year period
  - Still, cold extremes are significantly more common than heat extremes
  - Winter temperatures are warming at a faster pace than summer temperatures
  - Temperature variability is larger during the winter than in the summer
  - Changes in temperature distributions vary by location
    - Local nuances can effect trends (e.g. ocean influence in Boston, MA or Barnstable, MA)

STEP 1: NEW ENGLAND CLIMATE PROJECTIONS

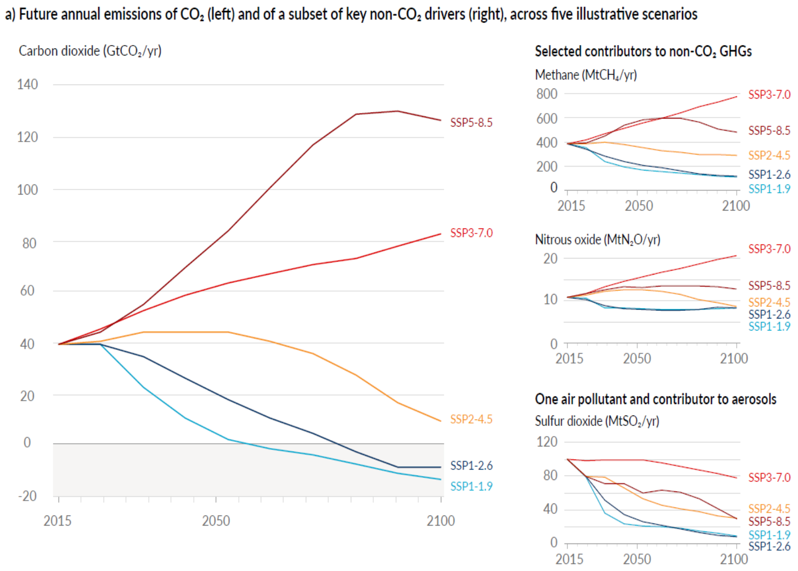
Introduction to Climate Projections

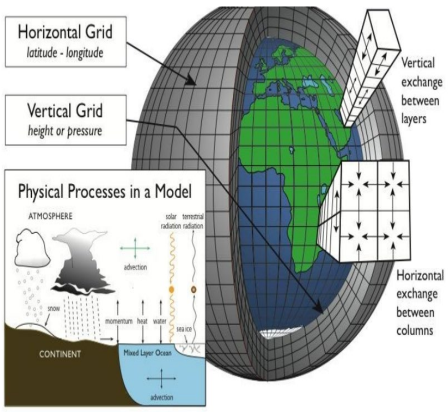
- Hourly profiles of weather variables produced via climate modeling techniques were used to develop hourly demand forecasts and energy output profiles for wind and solar resources for the periods being studied
- EPRI analyzed global climate model projections; projections of Hartford, CT and Boston, MA are summarized in this section of the report
  - Additional figures of projections of other cities are included in the Appendix of *May 17, 2022 NEPOOL Reliability Committee meeting*
- Latest Generation CMIP6 Scenario Results were used in this study
- EPRI selected five reputable global climate models (GCM) that span a range of climate sensitivities*
  - NOAA Geophysical Fluid Dynamics Laboratory: GFDL-ESM4 2.7°C
  - Max Planck Institute (Germany): MPI-ESM1 3.0°C
  - Meteorological Research Institute (Japan): MRI-ESM2 3.1°C
  - Institut Pierre-Simon Laplace (France): IPSL-CM6A 4.6°C
  - UK Met Office: UKESM1 5.4°C
- EPRI utilized two Intergovernmental Panel of Climate Change (IPCC)-selected "climate scenarios"
  - Shared Socioeconomic Pathway (SSP) 1-2.6 ambitious policy (global CO2 negative by 2075) – "lower scenario"
  - SSP3-7.0 NEW no-policy baseline – "higher scenario"

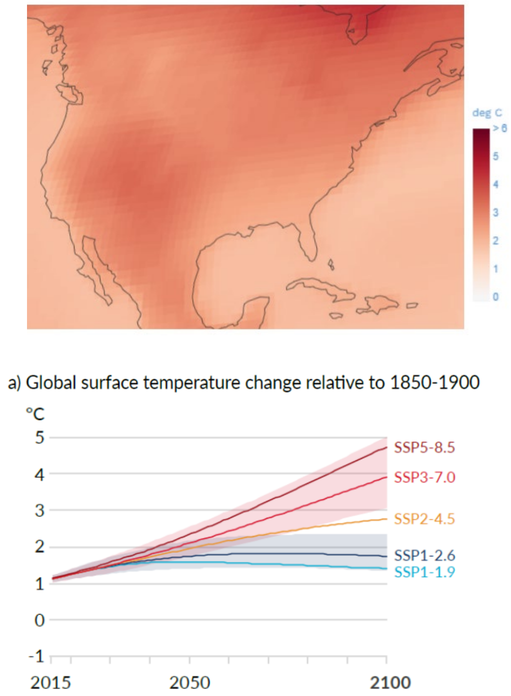
**Equilibrium Climate Sensitivity value (shown for each model above) summarizes a model's warming response; it reports the total amount of warming from a doubling of preindustrial CO2 concentrations. The 2021 IPCC WGI AR6 best estimate is 3°C, with a very likely range of 2 to 5°C (5-95% range). CMIP6 multimodel mean is 3.7°C (SD 1.1).*

Global Climate Models Translate Greenhouse Gas Scenarios To Climate Outcomes

Standardized Climate Scenarios ⇨ Global Climate Model (GCM) ⇨ Gridded Projection Data



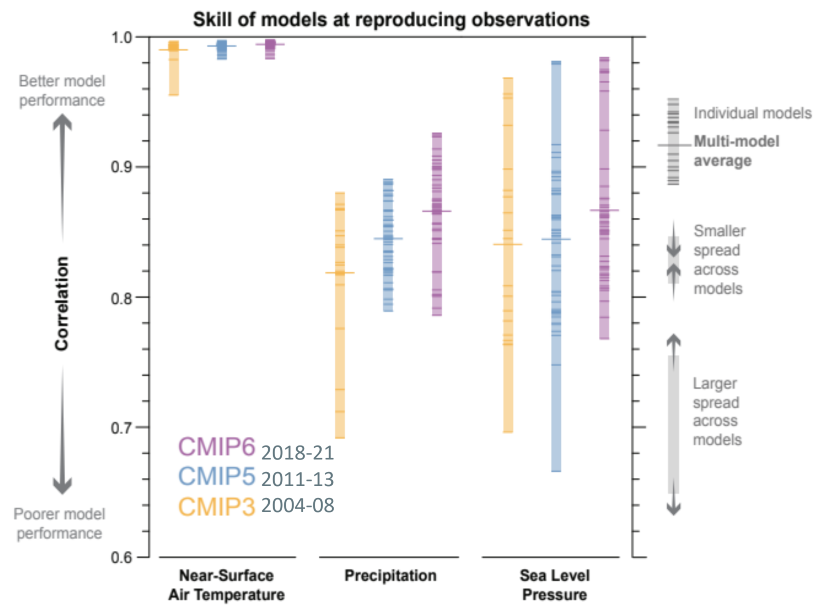


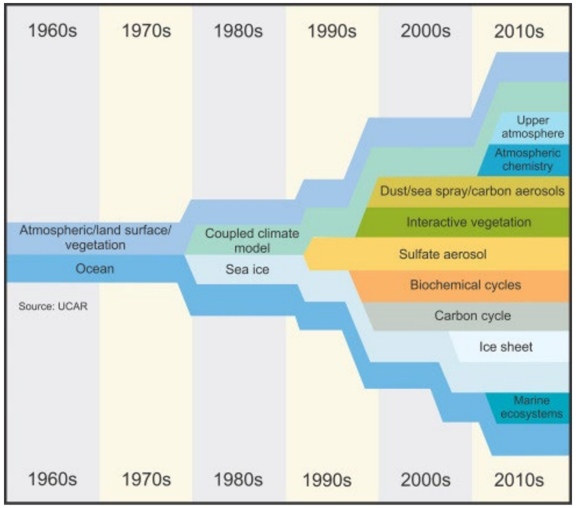


Figures: IPCC WGI AR6 Report (2021) SPM.4 (left) and SPM.8 (bottom right), GCM schematic by Jablonowski & Limon (2020), North America CMIP6 ensemble for 2C average warming (IPCC 2021)

Global Climate Modeling, Skill and State of the Science

- Scientists have most confidence in GCMs for climate variables that have large spatially coherent behavior
  - Temperature
  - Dewpoint
  - Overall increase in extreme precipitation
- Confidence exists in local scales because there is confidence in large scale behavior
- Not as much confidence in extreme events and severe storms
  - Small scale phenomenon that models don't explicitly simulate, e.g., tropical cyclones, strong winds, individual convective storms (like a Nor'easter)
- EPRI developed weather data for scenarios by leveraging robust information from climate models, alongside historical records to capture weather variability and synchronous profiles (e.g., temperature + wind + solar)





Figures: IPCC WGI AR6 FAQ 3.3 Fig 1 (top); UCAR (bottom)

STEP 1: PROJECTIONS OF TEMPERATURE TRENDS

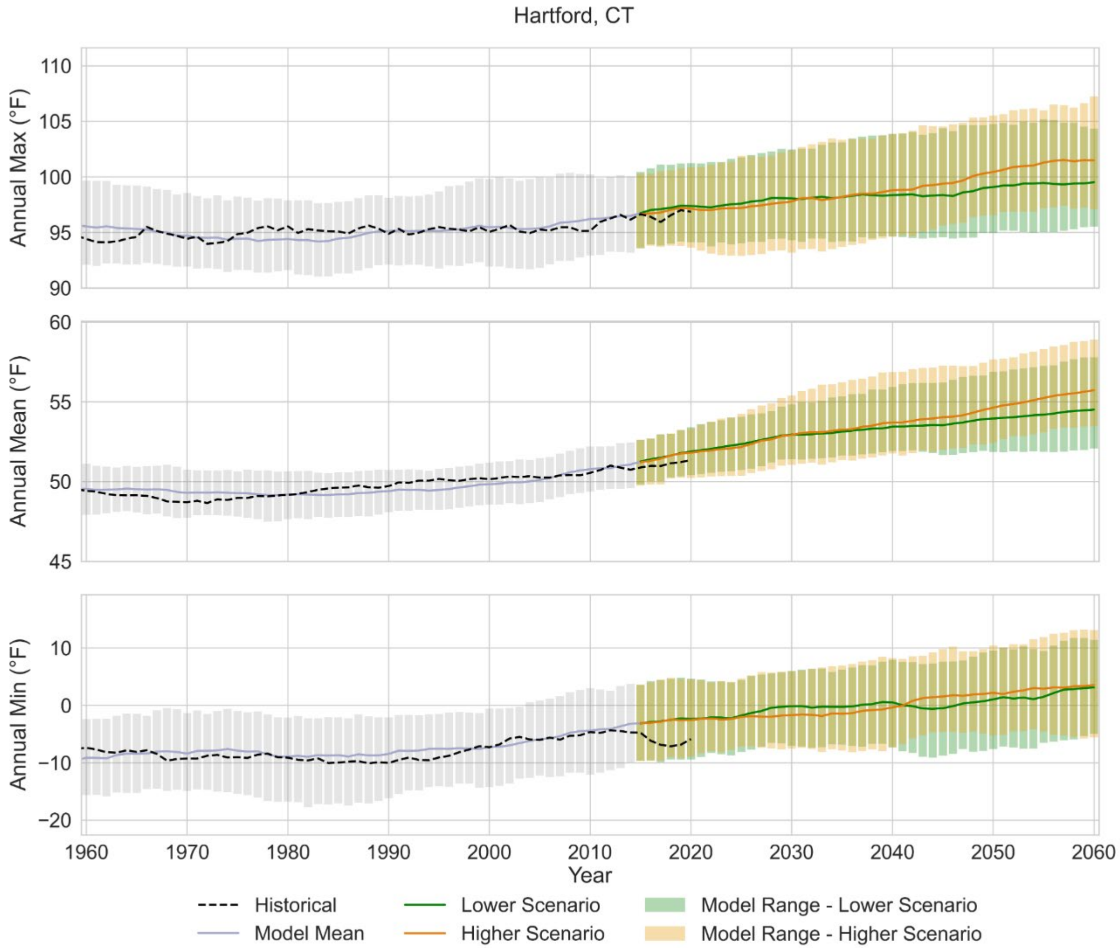
Temperature Projections - Hartford, CT

Overview

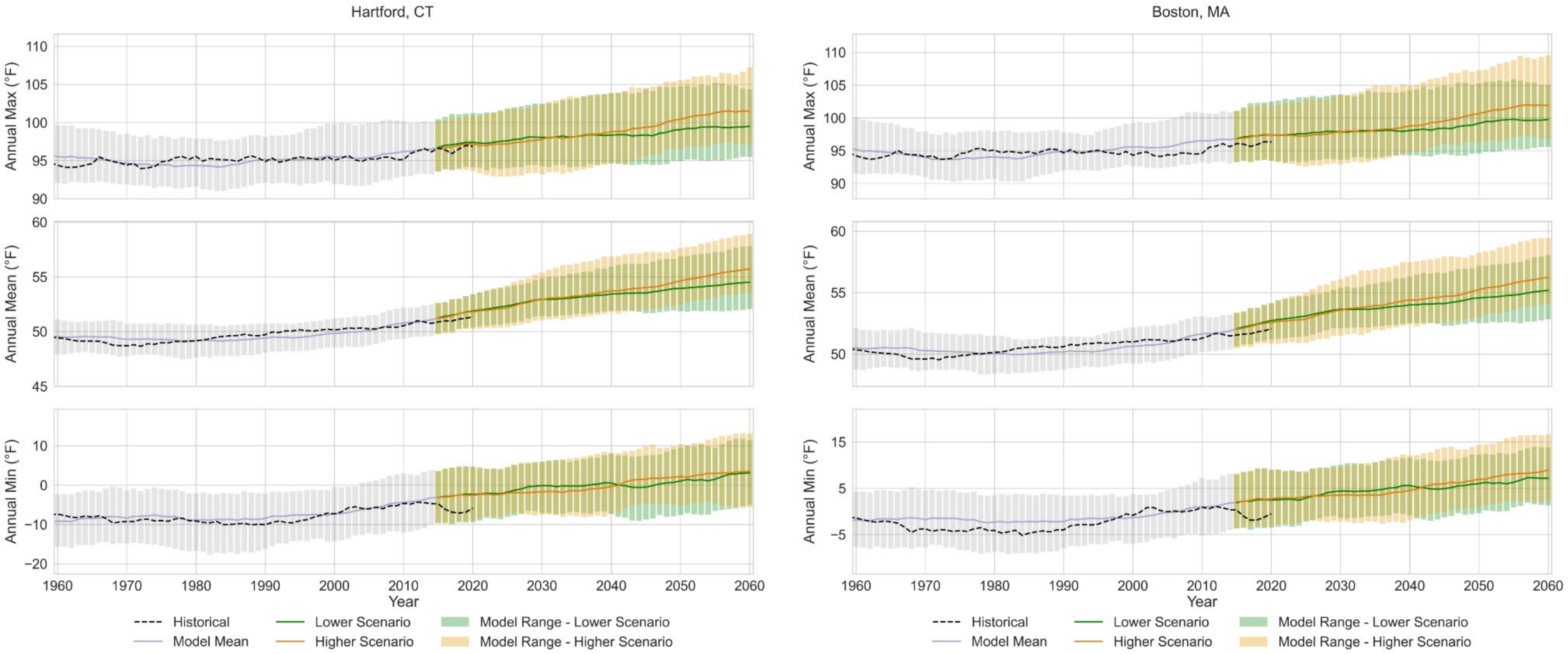
- This figure shows the smoothed changes in annual maximum, mean, and minimum temperature
- This plot is used to visualize directionality for annual minimum, mean, and maximum temperatures

Key Points

- Minimum and maximum temperatures are more variable than mean temperatures
    - There is a greater range across the models for minimum and maximum temperatures
- Historical climate model simulations have a lot of skill in replicating temperatures, particularly annual mean temperature



Temperature Projections
Boston, MA vs. Hartford, CT



Key Points

- There is a clear drop in annual minimum temperatures from the historical data that climate models do not pick up on
    - Climate models are more focused on long-term changes and are not designed to resolve all sources of natural climate variability, particularly near-term, natural climate fluctuations

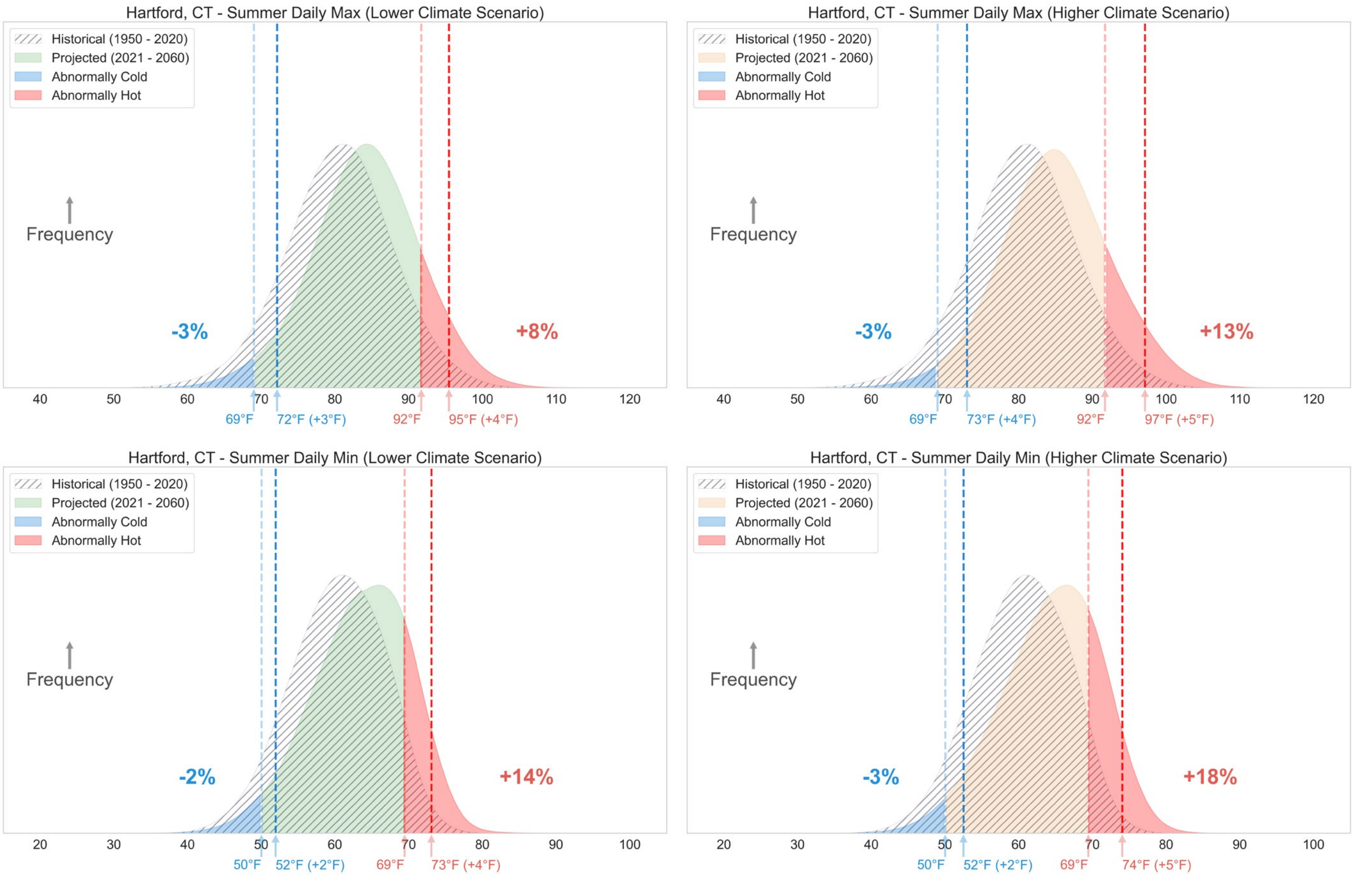
Summer Temperature Projections - Hartford, CT

Overview

- This figure shows the changing distribution of temperatures from the period of 1950-2020 to 2021-2060
- Changes in extremes (5th and 95th percentiles) are highlighted in blue (5th) and red (95th) shading
- Percentiles are defined by the season. Summer is the months of June – August; winter is the months of December – February

Key Points

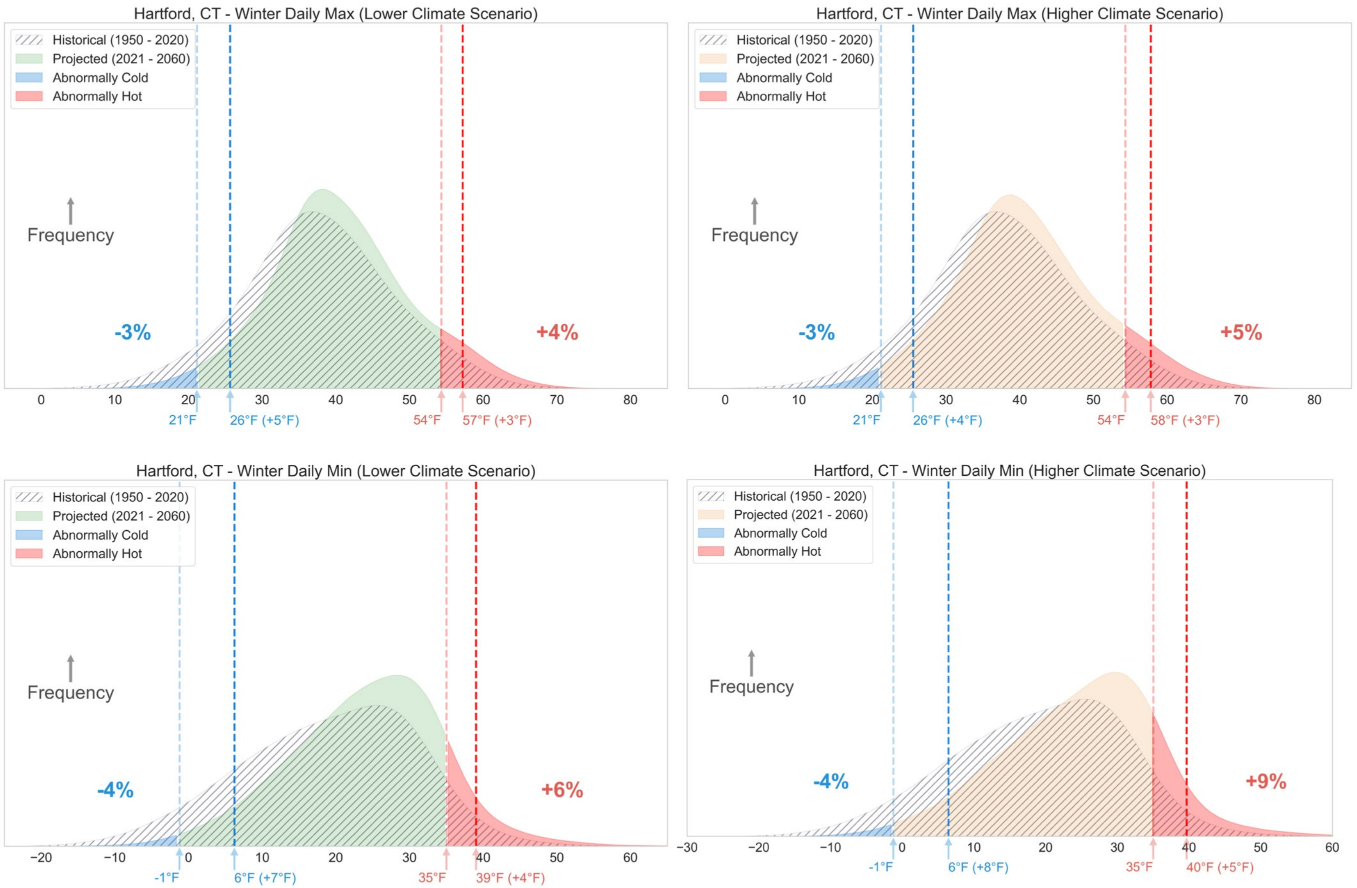
- Summer minimum temperatures in Hartford, CT are warming at approximately the same rate as maximum temperatures
- Warming is more pronounced in a higher climate scenario



Winter Temperature Projections - Hartford, CT

Key Points

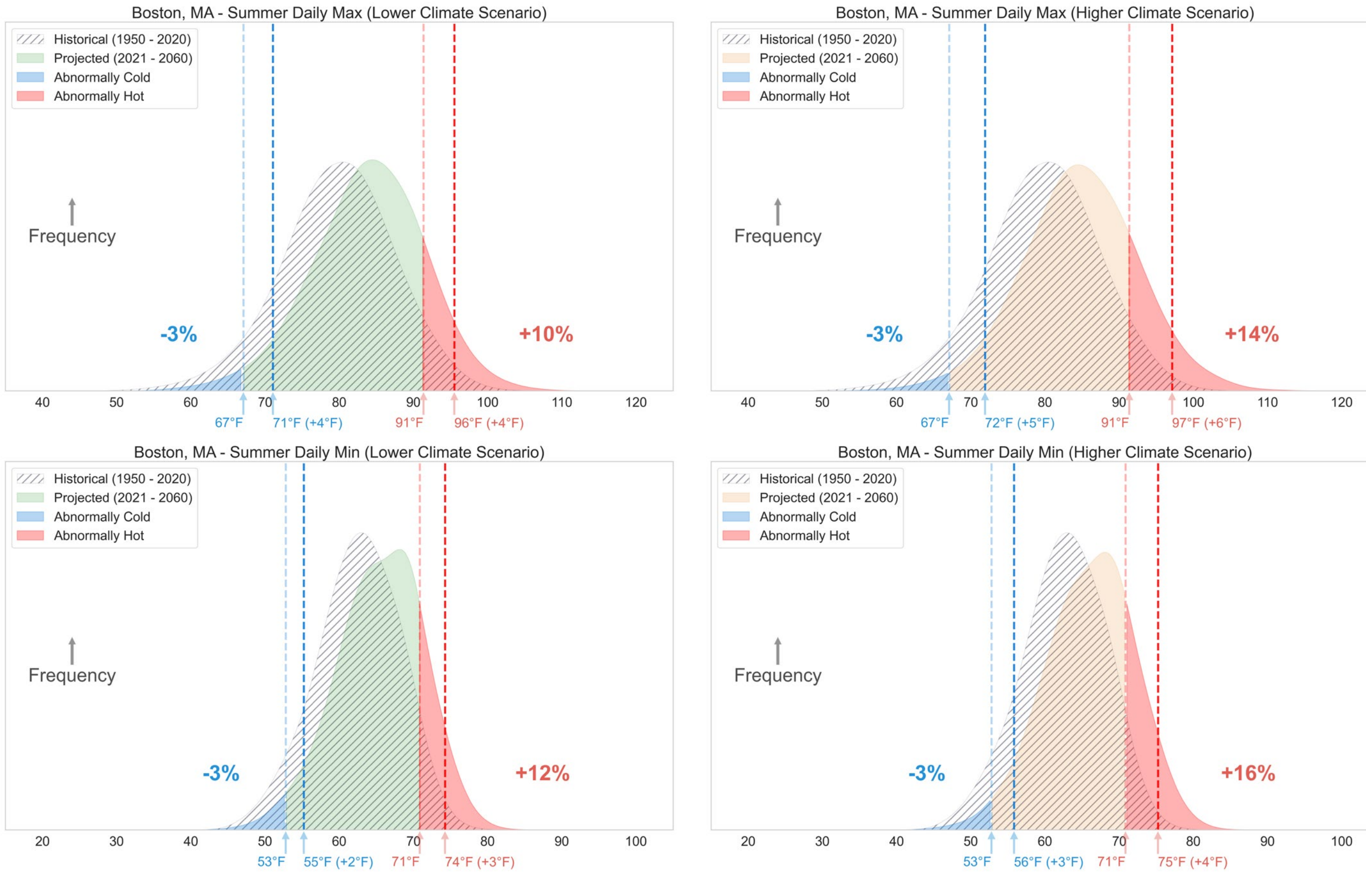
- Winter minimum temperatures are warming faster than winter maximum temperatures
- Warming is slightly more pronounced in a higher climate scenario



Summer Temperature Projections - Boston, MA

Key Points

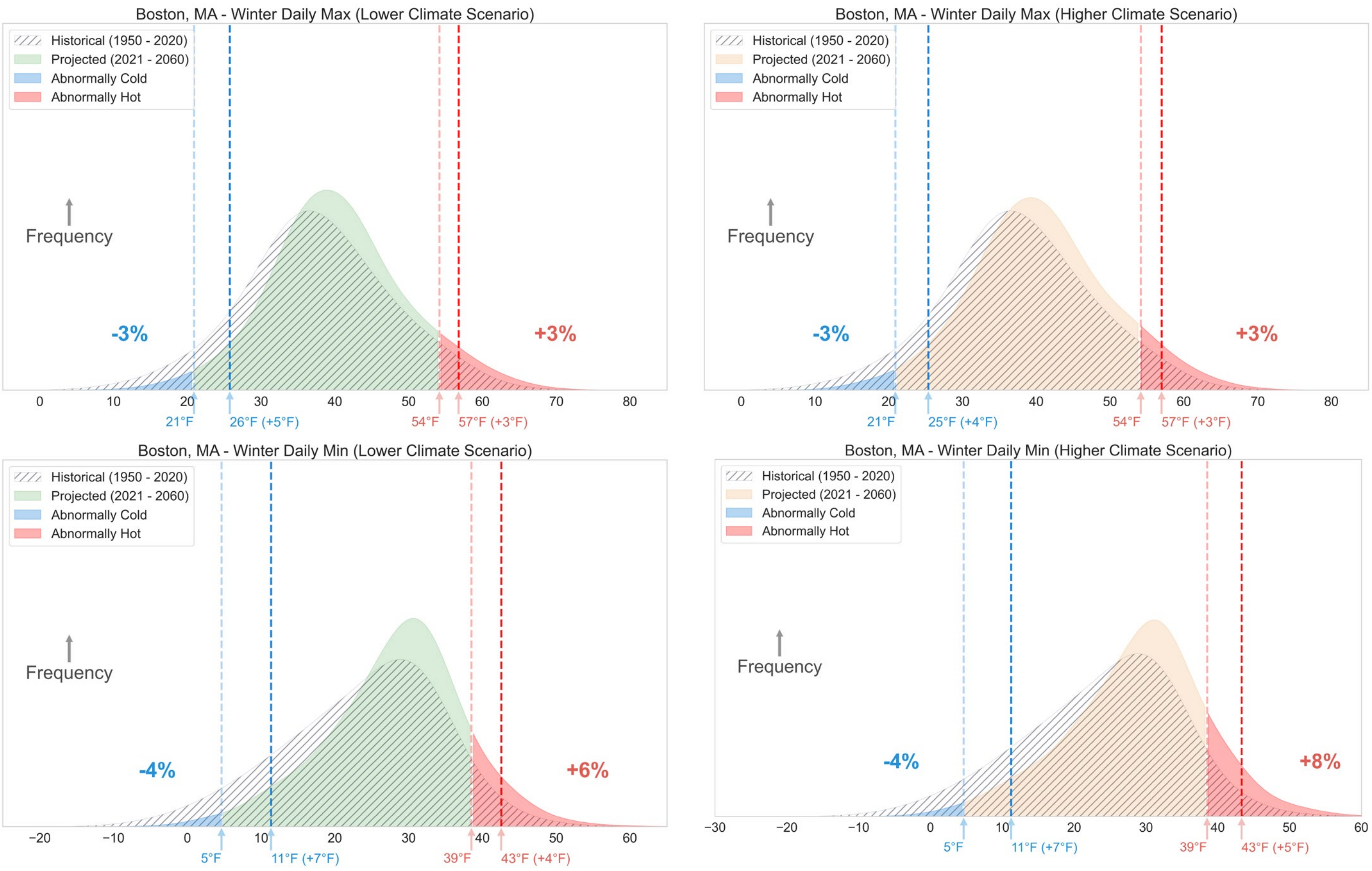
- The change in summer temperatures in Boston, MA is similar to Hartford, CT
- Warming is more pronounced in a higher climate scenario than in the lower climate scenario



Winter Temperature Projections - Boston, MA

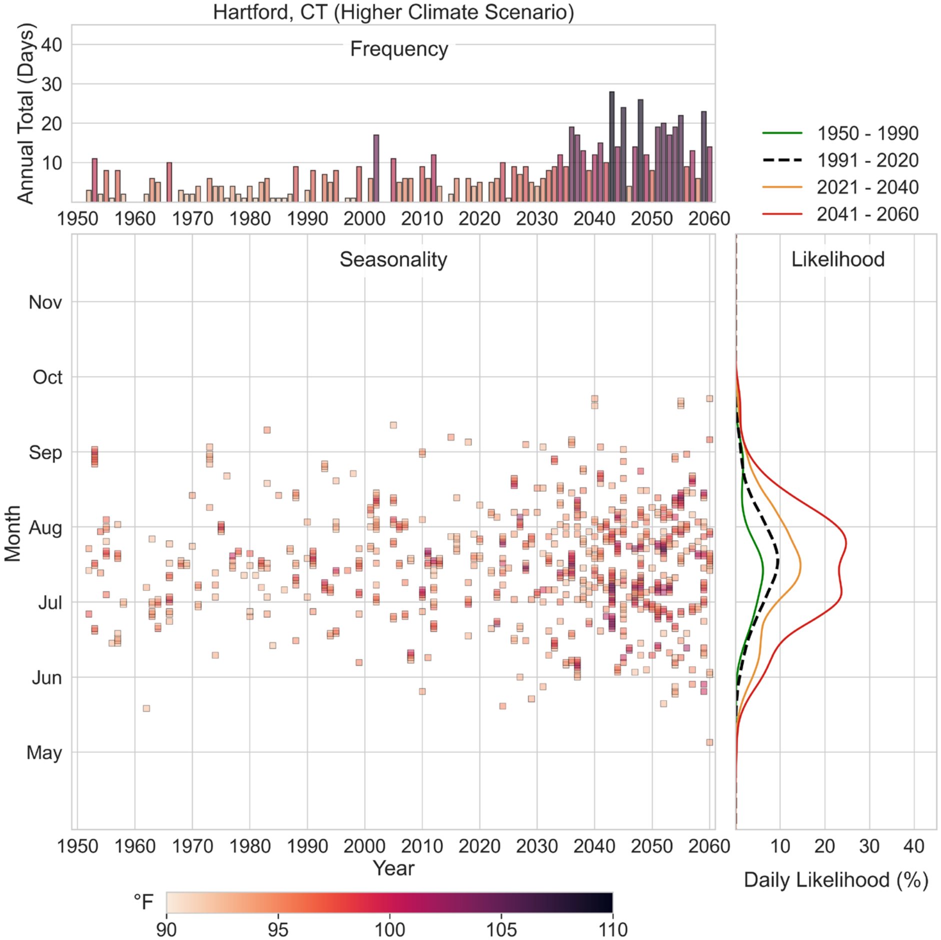
Key Points

- The change in winter temperatures in Boston, MA is similar to the change in winter temperatures in Hartford, CT
- Warming is more pronounced for minimum temperatures and in a higher climate scenario



STEP 1: PROJECTIONS OF TEMPERATURE EXTREMES

Extreme Heat Projections - Hartford, CT



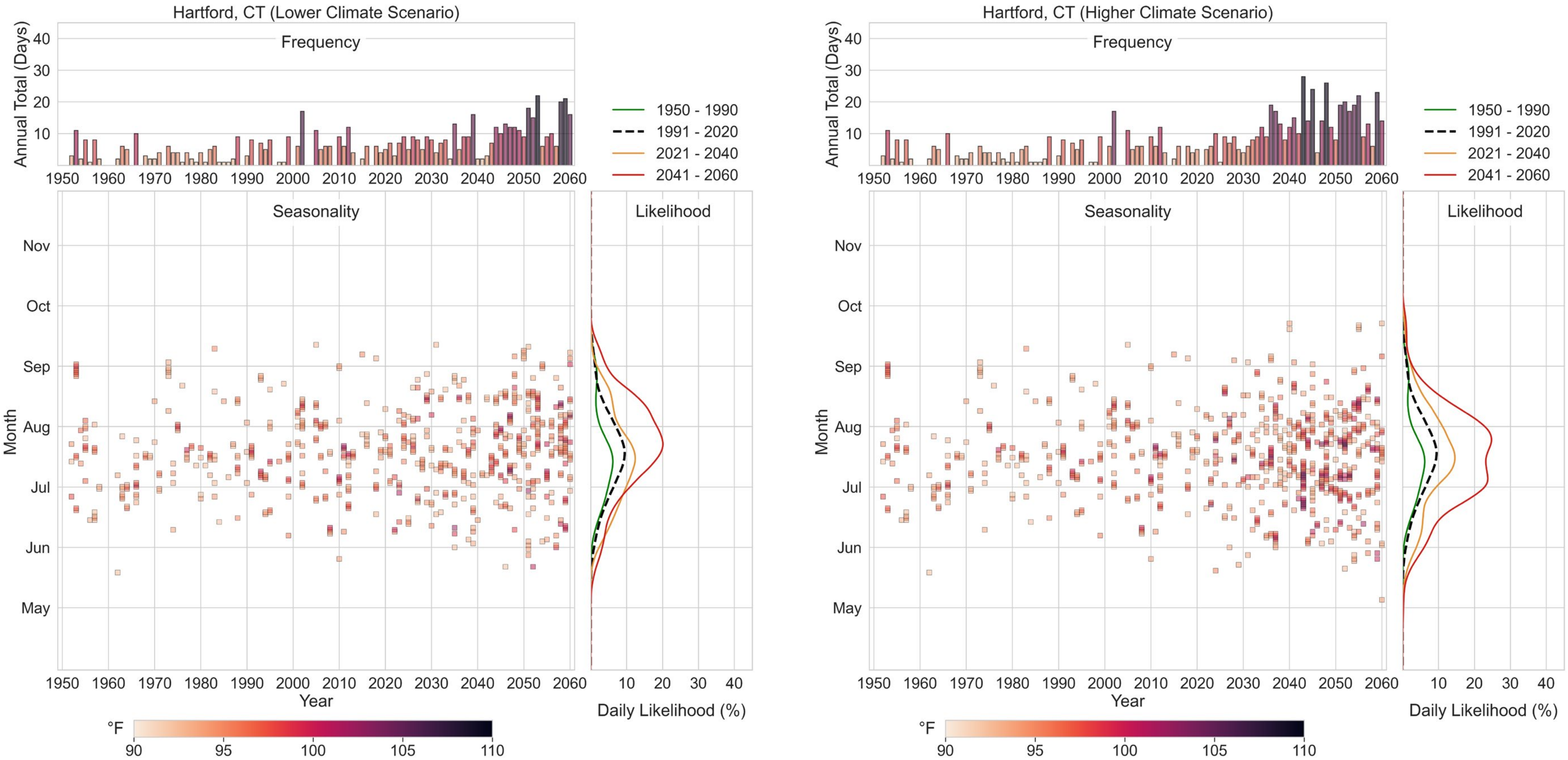
Overview

- This figure shows the frequency of extreme heat (top), the seasonality of extreme heat (main), and the likelihood of extreme heat by day of the year (right) from 1950 – 2060
- Extreme heat in this case is defined as a daily maximum temperature above the 95th percentile (90°F for Hartford, CT)
- 1991 – 2020 is the new climate normal period as defined by the National Oceanic and Atmospheric Administration (NOAA)

Key Points

- Extreme heat has increased in frequency in recent decades and is projected to increase in coming decades

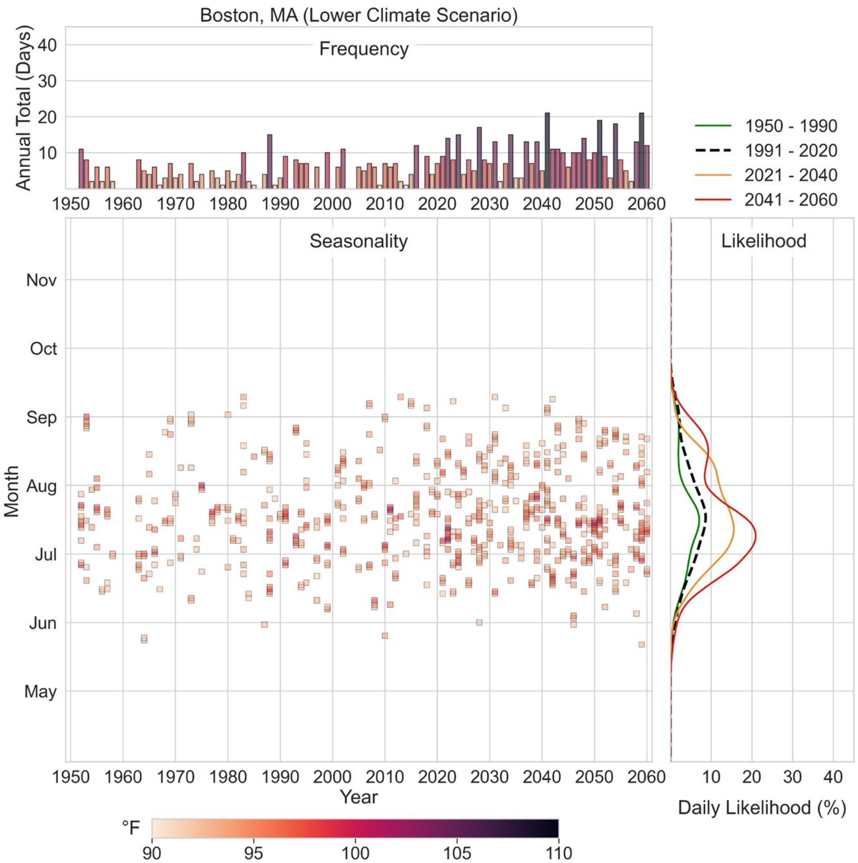
Extreme Heat Projections - Hartford, CT
Lower Climate Scenario vs. Higher Climate Scenario

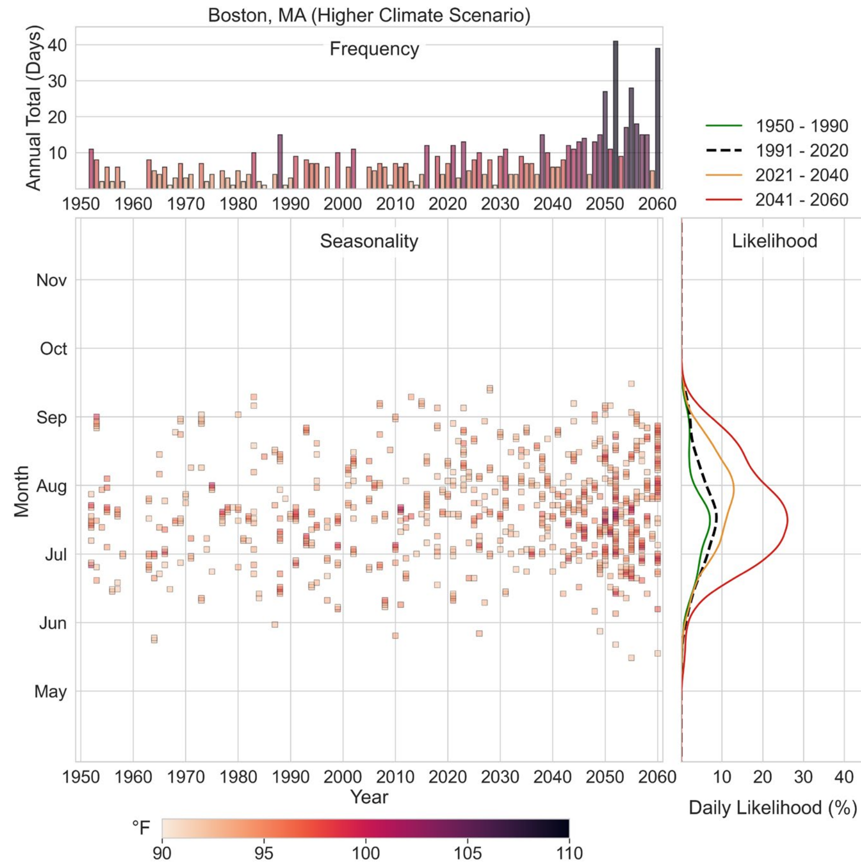


Key Point

- The two climate scenarios begin to diverge around 2050, with the higher climate scenario projecting more frequent extreme heat

Extreme Heat Projections - Boston, MA
Lower Climate Scenario vs. Higher Climate Scenario





Key Points

- As with Hartford, CT, the two climate scenarios begin to diverge around 2050
- The higher climate scenario shows the potential for more than 40 days above the historical 95th percentile by 2050

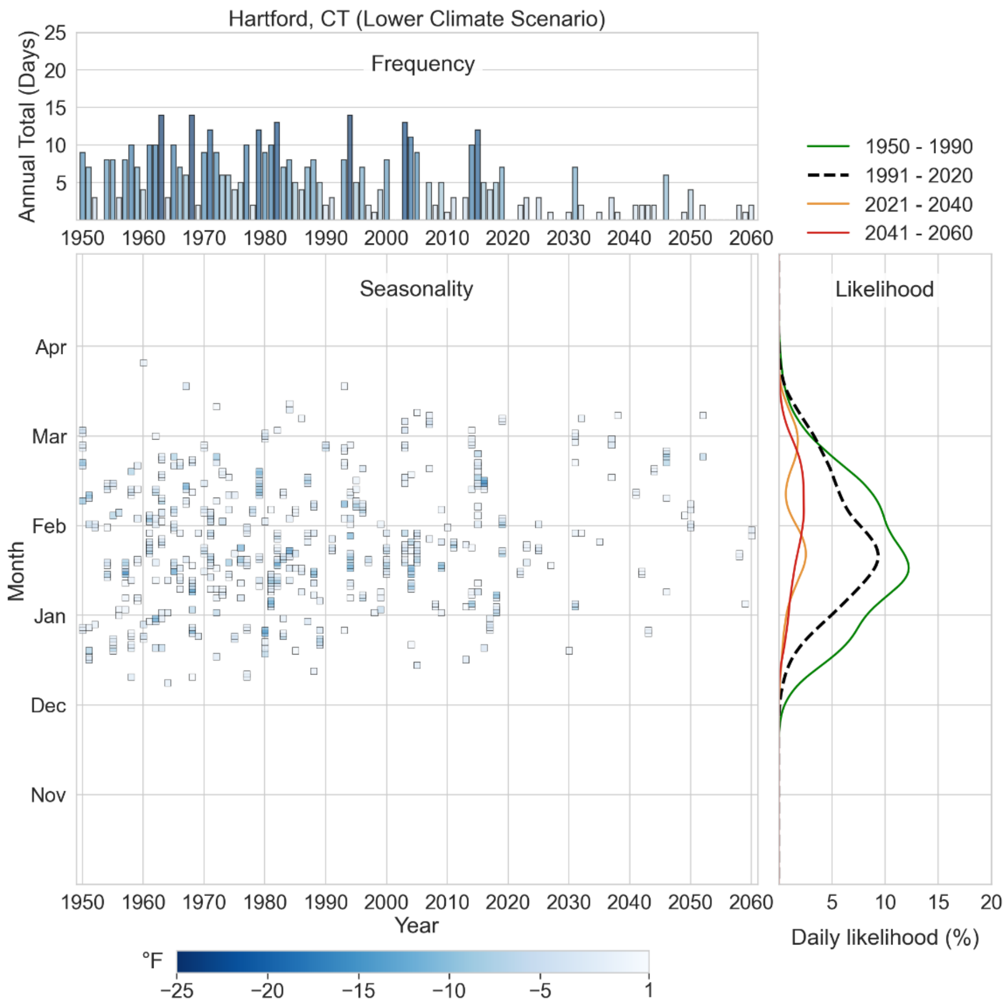
Extreme Cold Projections - Hartford, CT

Overview

- This figure shows the frequency of extreme cold (top), the seasonality of extreme cold (main), and the likelihood of extreme cold by day of the year (right) from 1950 – 2060
- Extreme cold in this case is defined as a daily minimum temperature below the 5th percentile (1°F for Hartford, CT)

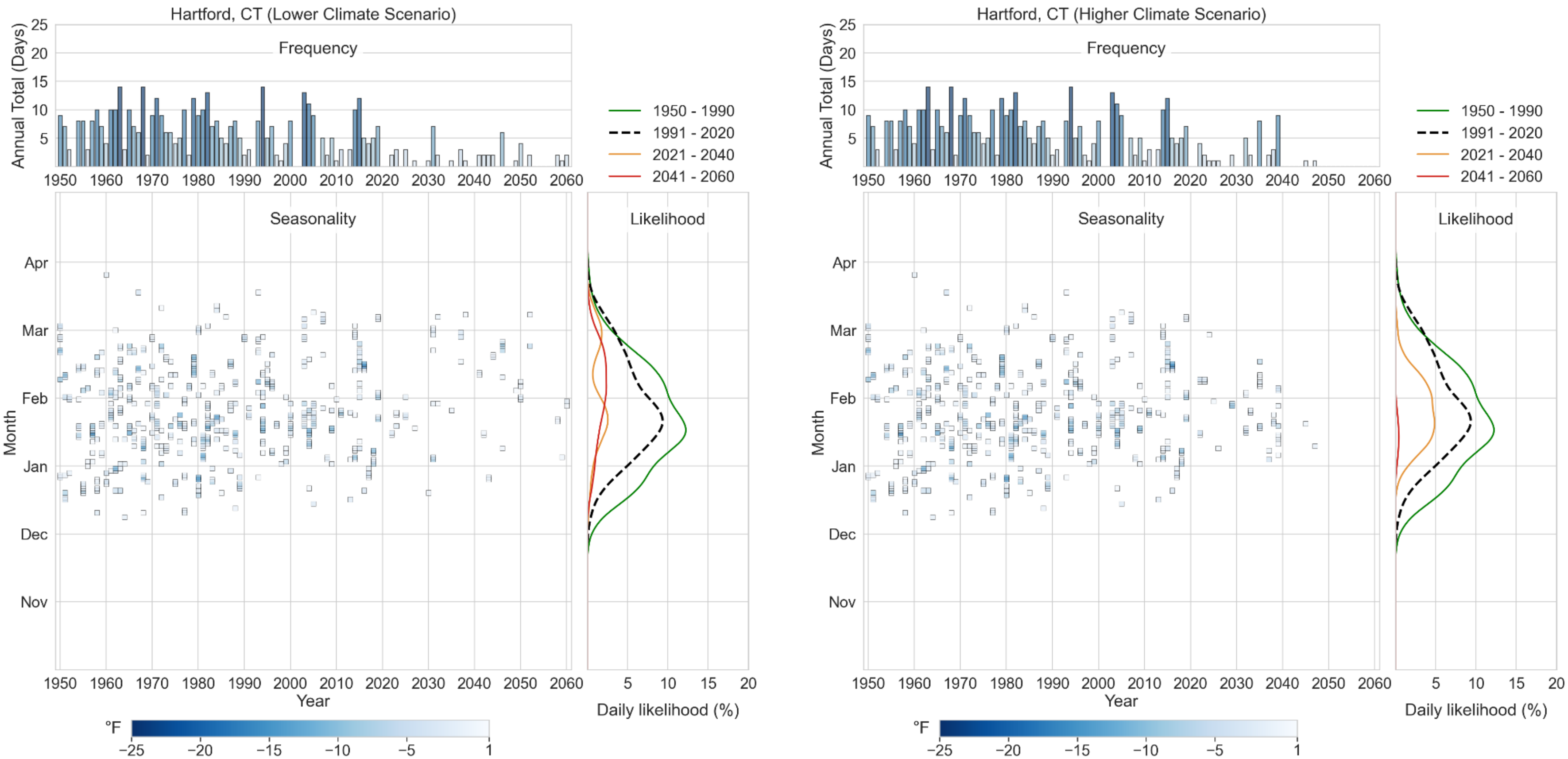
Key Points

- Extreme cold has decreased in frequency in recent decades and is projected to continue decreasing in coming decades
- Both Hartford, CT and Boston, MA have relatively few extreme cold days relative to other locations in New England because of their latitude



Extreme Cold Projections - Hartford, CT

Lower Climate Scenario vs. Higher Climate Scenario

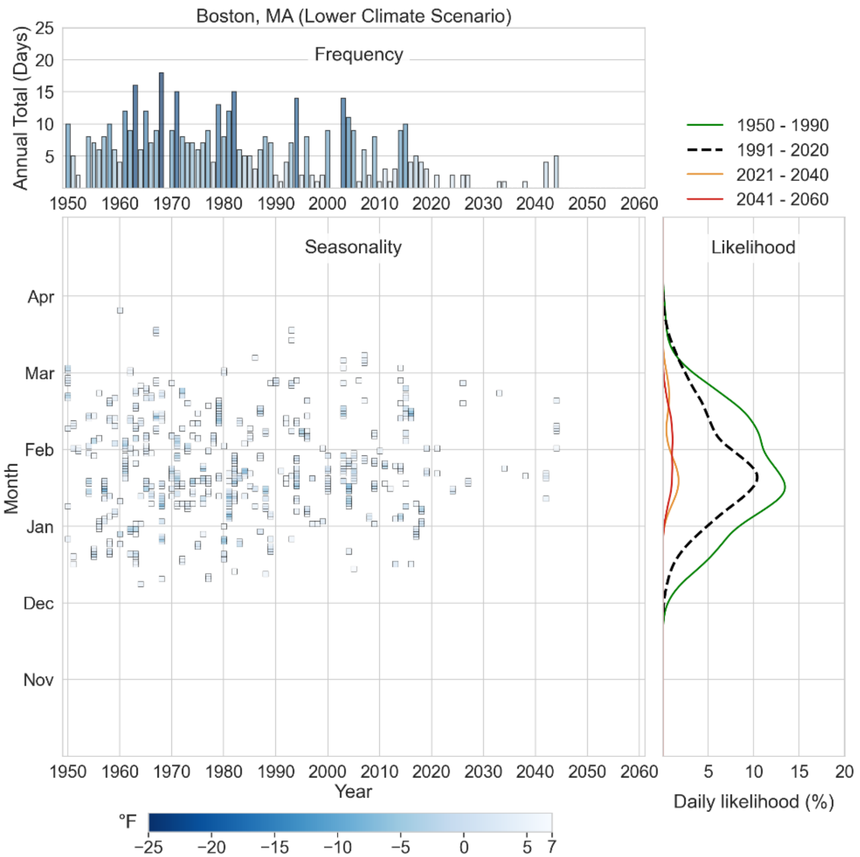


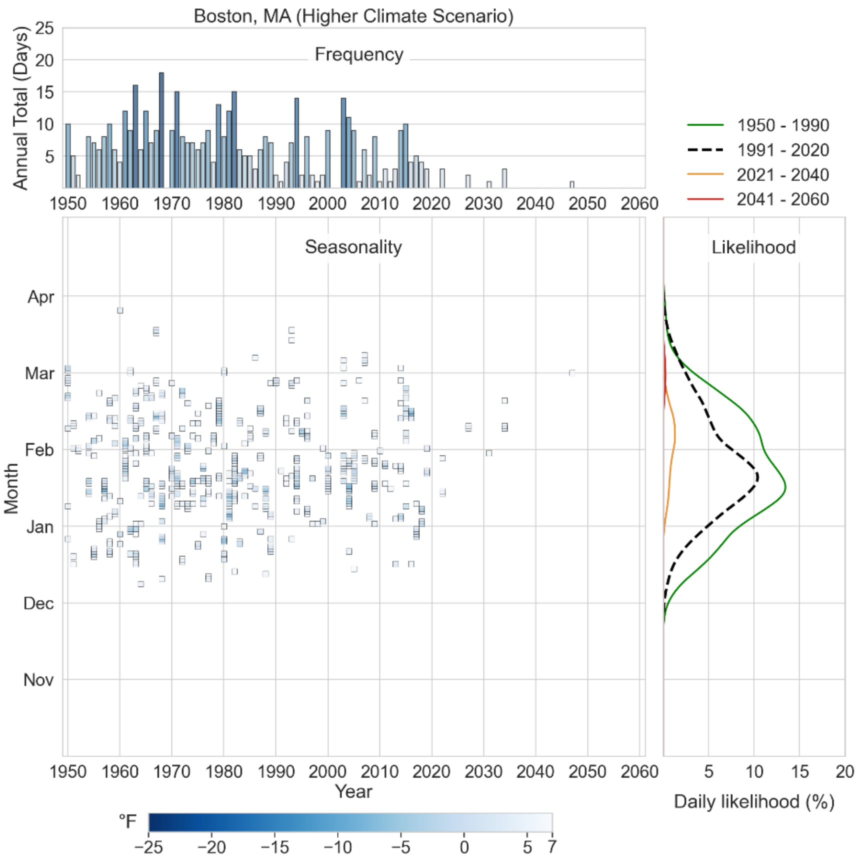
Key Points

- The frequency of extreme cold in Hartford, CT is relatively similar between climate scenarios until around 2040
- After 2040, only 2 days exceed the historical 5th percentile in the higher climate scenario

Extreme Cold Projections - Boston, MA

Lower Climate Scenario vs. Higher Climate Scenario





Key Points

- In both climate scenarios, Boston, MA has a larger decrease in extreme cold when compared to Hartford, CT
- Because of the proximity to water, Boston, MA is a bit more challenging to represent than Hartford, CT

STEP 1: PRECIPITATION AND WIND SPEED PROJECTIONS

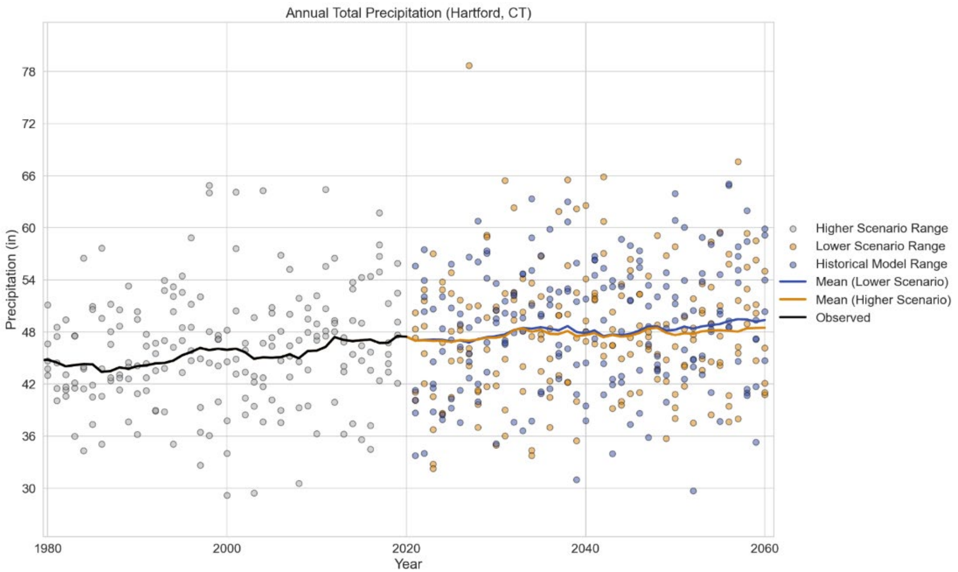
Precipitation - Hartford, CT

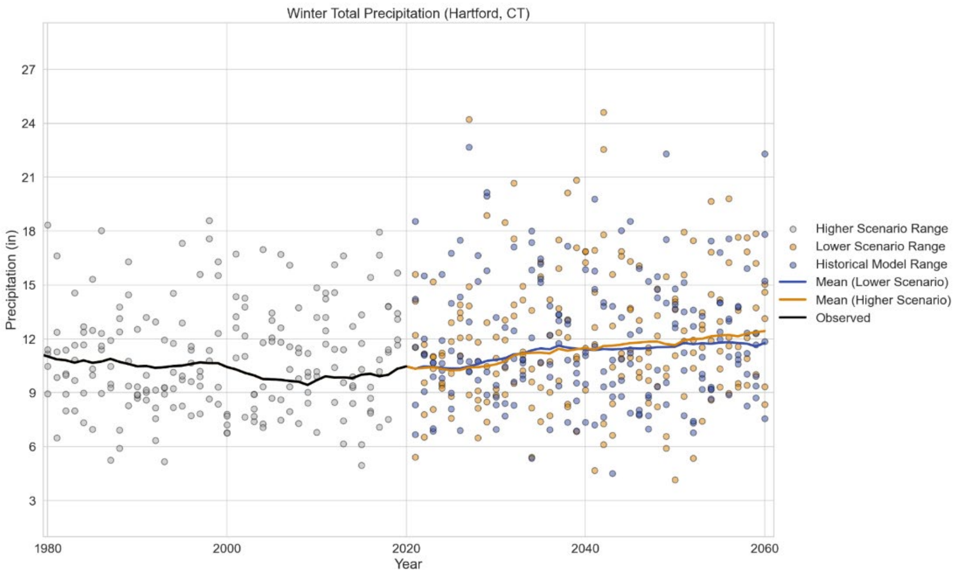
Overview

- This figure shows the historical and projected annual total precipitation and winter total precipitation from 1980 - 2060
- This is a sum of all rainfall and snowfall (snowfall converted to liquid water equivalent), smoothed with a 30-year rolling mean
- Winter is defined as the months of December – February

Key Points

- Annual total precipitation, as well as winter precipitation, is projected to increase in both scenarios
- There is more uncertainty in climate models around precipitation projections; there is little difference in annual total precipitation between the two scenarios
- The model range (model maximum – model minimum) is quite large for any given year

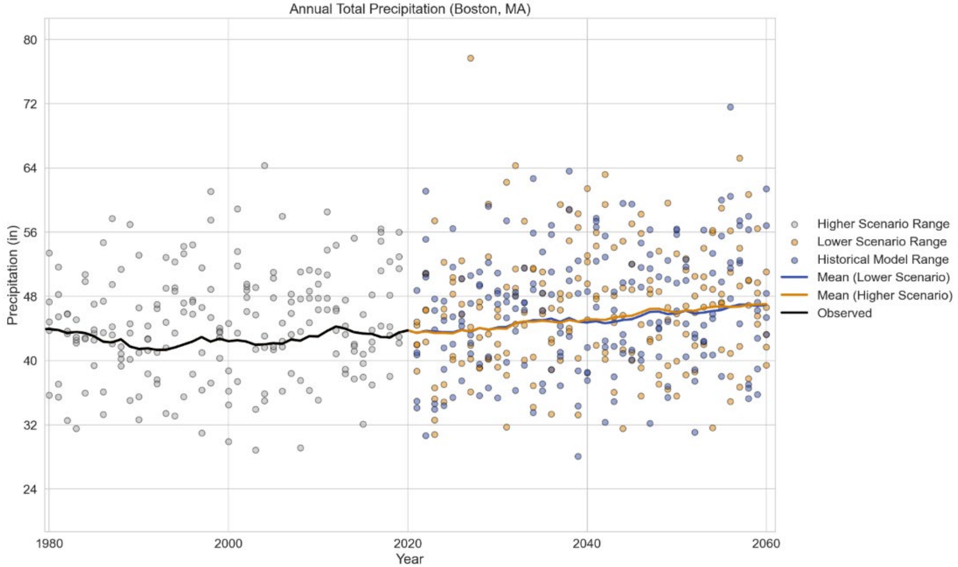


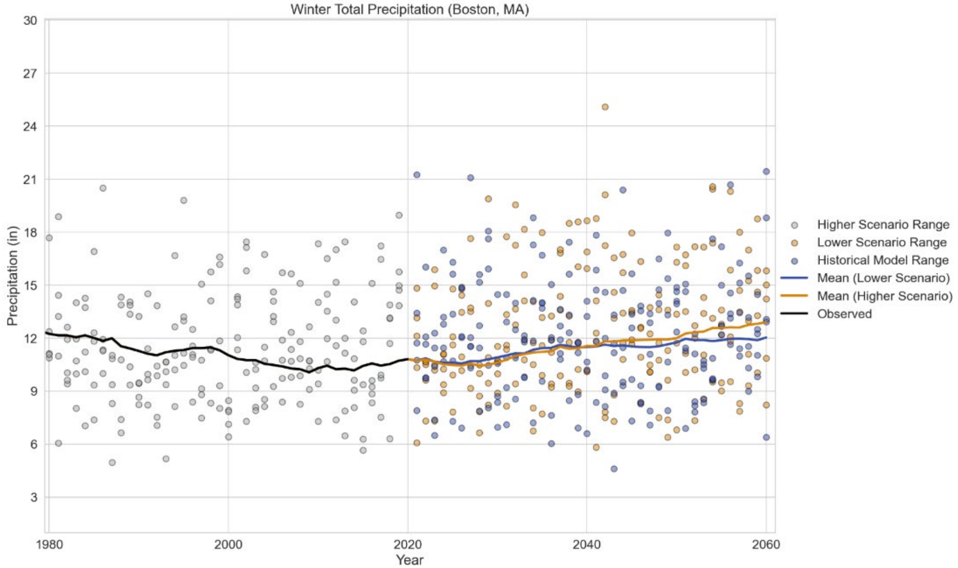


Precipitation - Boston, MA

Key Points

- The annual total precipitation for Boston, MA is similar to Hartford, CT and the projected change is similar
- Boston, MA winter precipitation is projected to increase more than Hartford, CT winter precipitation
- The projected increase in winter precipitation does not necessarily mean an increase in snowfall





Projected Changes in 10m Wind Speeds Across the United States

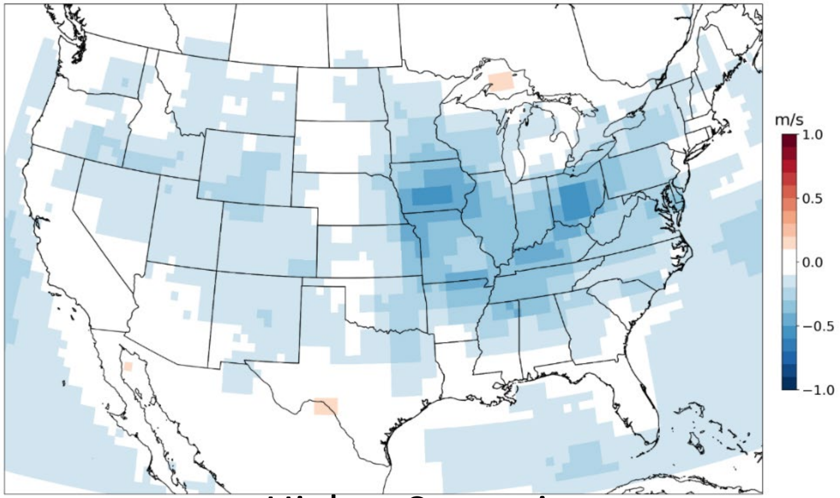
Overview

- These figures show the change in mean annual 10m wind speed from 1980 through 2060 across the continental US
- The trend is calculated with the historical climate model simulations and climate model projections to show how the climate models project wind will change

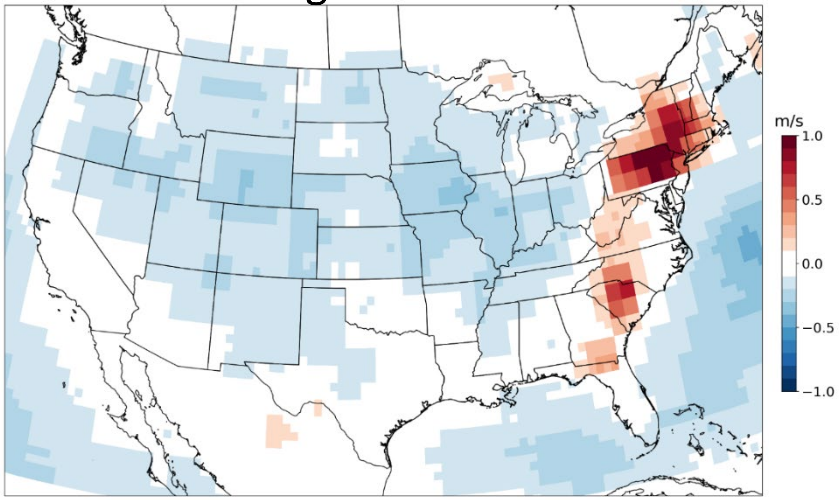
Key Points

- Climate models do not resolve wind speeds as well as temperature; coarse spatial and temporal resolution of climate projections makes it difficult to capture the natural fluctuations of wind speeds and periods of low and high wind speeds at specific locations
- Projected changes in wind speed through 2060 are generally much smaller than changes in wind speed from year to year
- The Northeast has the largest projected changes in wind speeds, under the higher climate scenario, when compared to the rest of the US

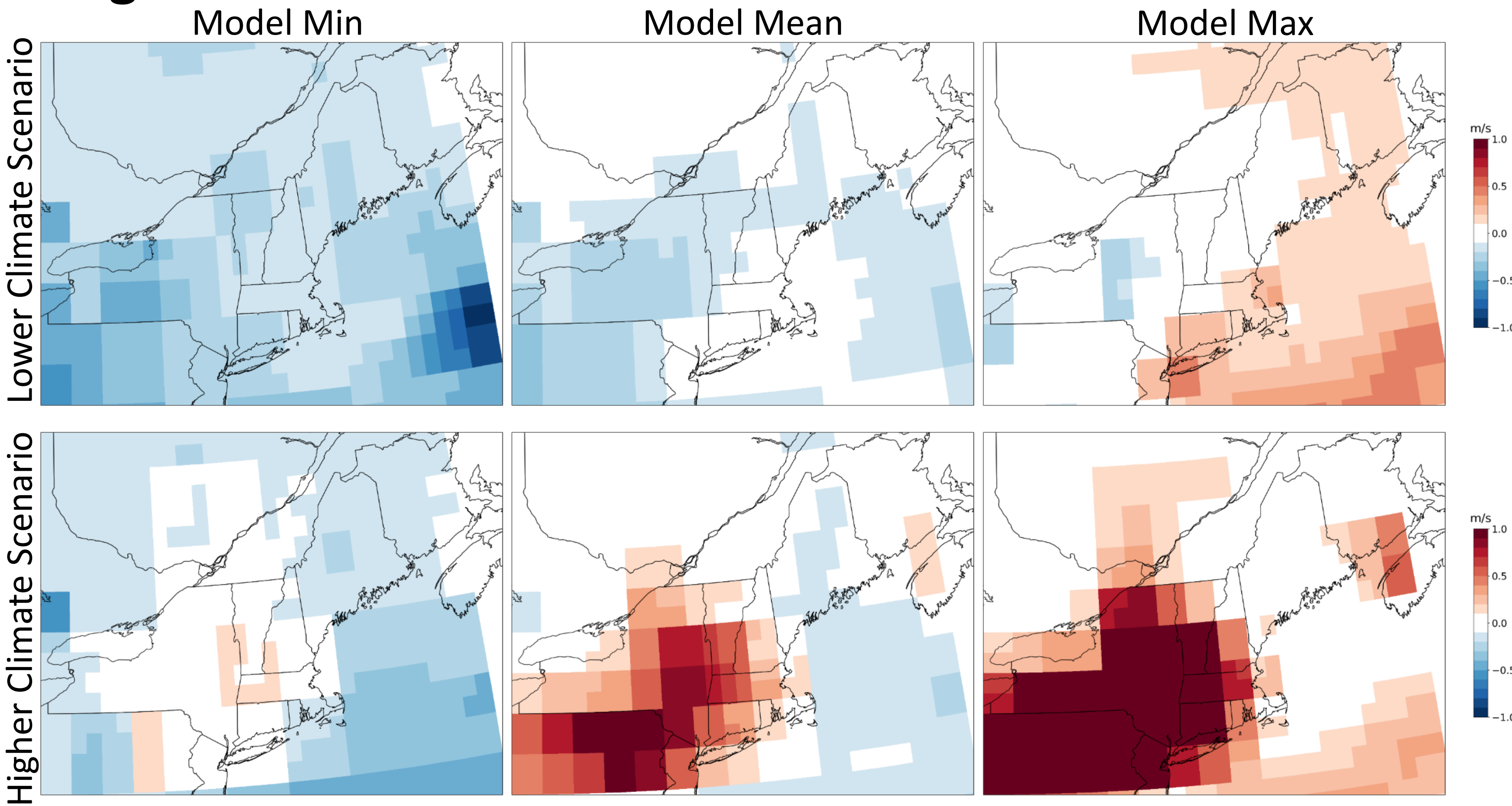
Lower Scenario



Higher Scenario



Projected Changes in 10m Wind Speeds Across New England



Key Points

- Across the different climate models and climate scenarios, there is a wide range of projected changes in wind speeds by 2060
- The higher climate scenario tends to show higher wind speeds across the Northeast

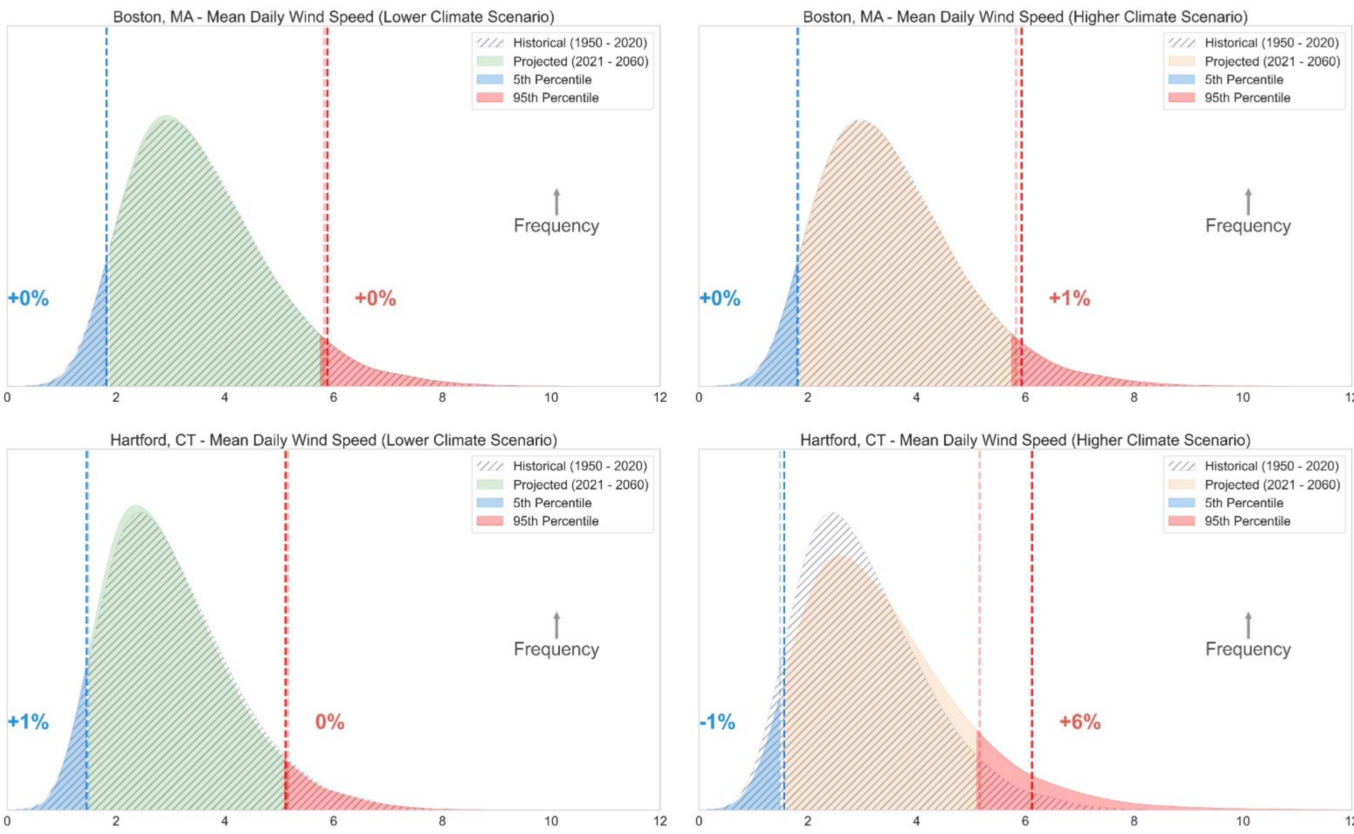
Wind Distributions - Boston, MA and Hartford, CT

Overview

- This figure shows the changing distribution of 10m wind speeds from the period of 1950-2020 to 2021-2060
- Changes in extremes (5th and 95th percentiles) are highlighted in blue (5th) and red (95th) shading

Key Points

- Projected changes in wind speeds are higher for Hartford, CT than Boston, MA under a higher climate scenario
- A lower climate scenario shows little change in wind speeds



Analysis of Climate Projections

Summary of Key Takeaways

- Minimum and maximum temperatures are projected to have a more pronounced trend than mean temperatures
- In general, summer and winter minimum temperatures are warming faster than summer and winter maximum temperatures
- As expected, warming is more significant in the higher climate scenario while differences across independent climate models can be greater in the near-term than differences between scenarios
- Extreme heat has increased in frequency in recent decades and is projected to continue to increase in coming decades while extreme cold has decreased in frequency in recent decades and is projected to continue to decrease in coming decades
  - Higher latitude locations are expected to continue experiencing more extreme cold than lower latitude locations
  - With regard to extreme heat, climate scenarios begin to diverge around 2050; with regard to extreme cold, climate scenarios begin to diverge earlier, around 2040

Analysis of Climate Projections, cont.

Summary of Key Takeaways

- Precipitation is expected to increase modestly in both climate scenarios though there is more uncertainty with respect to precipitation projections
- Trends in wind speed projections are smaller than the expected year-to-year variability in wind speed, however some increase in wind speed is expected depending on the location

STEP 1: HOURLY WEATHER VARIABLES PROFILES FOR 2027 AND 2032 STUDY YEARS

Development of Hourly Weather Variable Profiles – A Key Input to Step 2

- The objective was to develop future weather realizations consisting of hourly synchronous profiles for temperature, wind, and solar that reflect climate model trends and projections, which are limited to daily averages
- Needs
  - Capture range of future weather possibilities indicated by GCM projections
  - Preserve hourly temperature characteristics (including diurnal variability and seasonal aspects)
  - Preserve synchronous profiles for temperature plus wind and solar
- Approach
  - Leverage the best of both datasets, hourly historical ERA5 and daily projected GCM
  - The historical data provides 72 years of actual hourly weather realizations
  - The projection data provides the magnitude of change at all points of the distribution –this is used to define a delta quantile mapping approach
    - determine the projected changes (delta) in variables at specific quantiles, and apply that delta to the historical data to create synthetic future realizations

Interpretation of Future Weather Realizations

- Each historical year (1950 – 2021) is one potential future weather year
- Using the 5 GCMs and 2 climate scenarios, the 72 historical years are turned into 720 potential weather realizations for any future year of study
- While future years are expected to be warmer, the general diurnal patterns, day-to-day and inter-annual variability should be pretty similar

Hourly Weather Variable Profiles

- Each future weather realization is a single year of synthetic hourly data
- There are 720 realizations for each projected year
  - 72 historical weather years (1950-2021)
  - 5 climate models & 2 climate scenarios each model (10 total)
  - 72 historical weather years x 10 model and scenario combinations = 720 realizations
- Hourly weather variable profiles are high-dimensional
  - Dimension 1: Time series of data for each weather variable (temperature, wind speed, dew point, etc.)
  - Dimension 2: locations (10 weather stations)
  - Dimension 3: 2 climate scenarios (lower scenario & higher scenario)
  - Dimension 4: 5 climate models
  - Dimension 5: Year in which the synthetic profiles are valid (2027 & 2032)

STEP 2 – RISK SCREENING MODEL AND SCENARIO GENERATION

Overview of Step 2

- The objective of Step 2 is to identify 21-day weather events of interest and develop the inputs to the 21-day energy assessment in Step 3
- Key activities in this step include:
  - Risk Screening Model, which is used to facilitate selection of extreme events by searching the weather data obtained in Step 1
  - Event selection, which identifies events of interest from the results of the Risk Screening Model
  - Scenario generation, which develops the input to the 21-day energy assessment in Step 3
- This section of the report reviews these key activities

Step 2 - Risk Screening Model Is Used To Facilitate Selection of Extreme Events For Study

- The objective of Risk Screening Model is to search the weather data set and select a set of 21-day events that appear most extreme to the future New England power system in terms of energy availability
  - This risk screening model is a coarse measure of system risk (supply and demand)
- 2 target years as part of the initial study, 2027 and 2032
- For purposes of the Risk Screening Model
  - The generation fleet in each target year is based on the set of resources that cleared FCA 16 in addition to state-sponsored resources that are either under contract or have been selected under recent RFP's
  - The demand profiles in each target year incorporate ISO's heating and transportation electrification forecasts in 2022 CELT
- For each year of study
  - The initial input to the Risk Screening Model is 37,440 events, based on 72 weather years (1950 – 2021), climate-adjusted according to five climate models and two climate scenarios
  - The output of the Risk Screening Model is 1,470 high risk 21-day events (top ~4% of possible 21-day events)

Step 2 - Event Selection

- 21-day events selected by the Risk Screening Model are likely to have significant similarities
  - Same weather event happening at a different moment
- To avoid studying very similar events, the K-means clustering technique was used to group similar events into clusters; several clusters were identified for each year of study
- A few representative events (e.g., the event with highest calculated risk) were selected from each cluster
- EPRI determined a “return period” for each cluster in order to describe the frequency (i.e. likelihood) that selected events from each cluster could be expected to occur in future

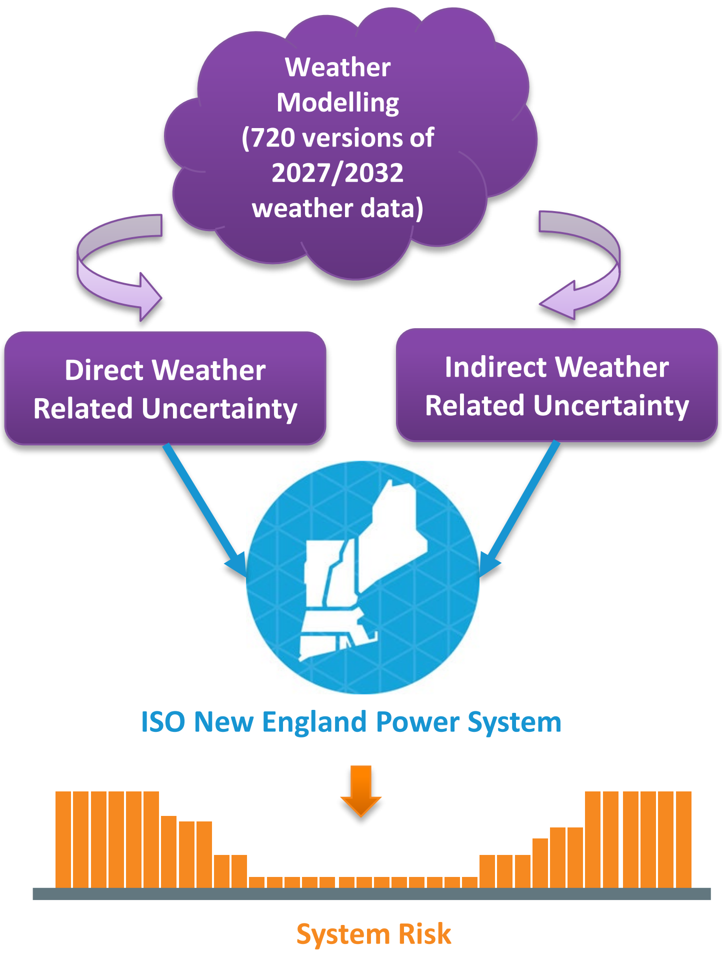
Step 2 - Power System Scenario Generation

- Following the selection of events for study, a complete set of cases and their probabilities was developed as an input to the 21-day energy adequacy studies in Step 3
- The objective of the scenario generation step was to develop a range of possible cases that incorporate the following uncertainties and their likelihoods:
  – Indirect-weather related uncertainties that may occur during the event and may influence resource (or energy) availability, and
  – Random forced outages and maintenance outages
- Scenario trees were developed to capture the various uncertainties

STEP 2 – RISK SCREENING MODEL

Objective of the Risk Screening Model

- To search the weather data set and select a set of discrete events that appear most extreme to the future New England power system in terms of energy availability
- Discrete events will be 21-day periods consisting of weather characteristics that place regional energy supplies at higher levels of risk
  - Multi-day weather events having weather characteristics similar to hurricanes or Nor'easters could be identified by the risk screening model to the extent that they are identified as being impactful to the region's energy supplies
- The Risk Screening Model is a coarse measure of system (supply and demand) risk; this model is intended to identify events for further study, not to quantify system energy adequacy under specific conditions
  - Energy assessments in Step 3 will quantify system energy adequacy risks under extreme weather events using the outcomes of Step 2



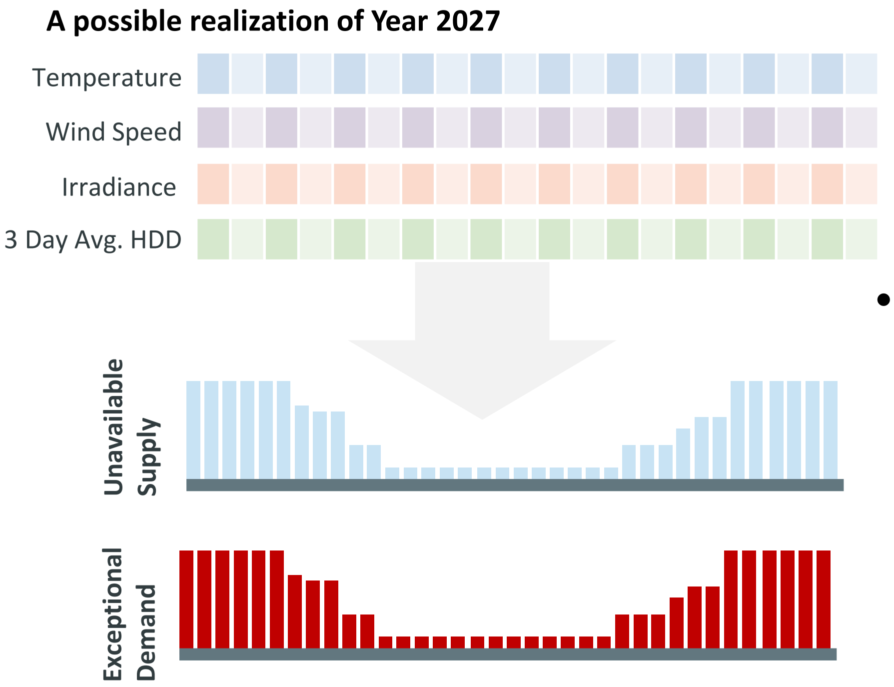
Risk Screening Model: Defines Relationships Between Generator Availability and Weather Conditions

- Relationships between generator availability and weather conditions were defined as part of the risk modeling
- Typical weather-related operating limitations by resource type were defined (see generic examples below)
  - Wind resources require wind speed between 4-25 m/s
  - PV resources require irradiance above 300 W/m^2
  - Combustion Turbines require ambient temperatures above 0°F and below 120°F
- De-ratings outside of normal operating range were estimated (see generic examples below)
  - Wind speed < 4 m/s = 100% derate
  - PV irradiance < 300 W/m^2 = 100% derate
  - Ambient temperatures > 95°F = 5% derate
- These relationships were defined for all generator technology types expected to be operating in the New England region in the years of study

Risk Screening Model: Considers Direct & Indirect Impacts of Weather

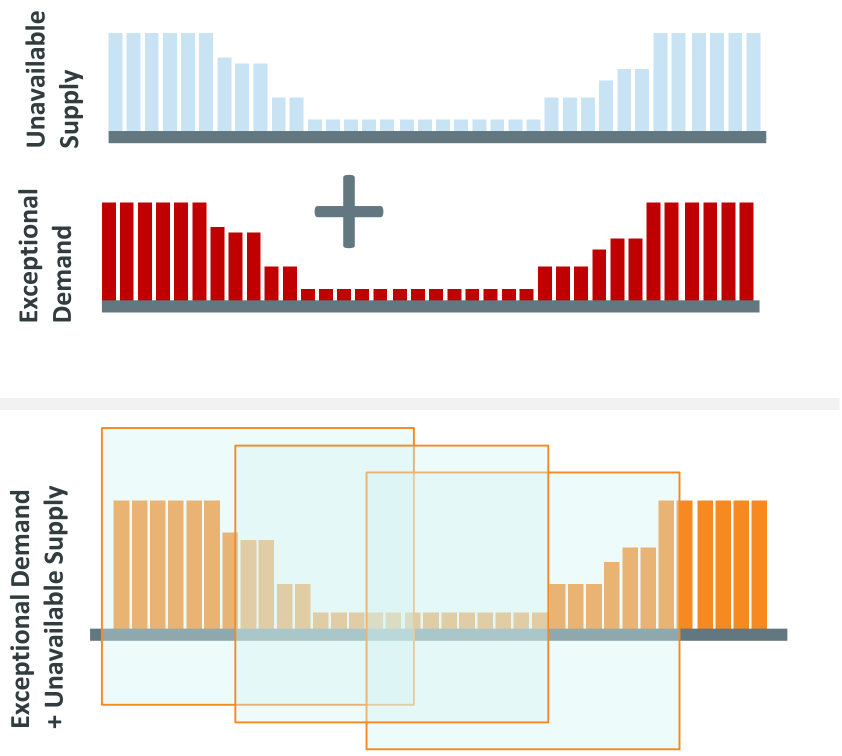
- The mechanism by which weather influences the availability of a generator or demand may be classified into two groups:
  - Direct Impacts: represent the dependence between generator performance and the weather conditions at a particular location at a given time
    - *Example: Wind output is a function of wind speed at the site*
  - Indirect Impacts: represent the dependence between generator performance and conditions arising subsequent to a given weather condition near the generator
    - *Example: Gas plant fuel supply is a function of heating demand that is a function of weather*
- Both direct and indirect impacts are considered in the Risk Screening Model

Risk Screening Model: Searches Weather Data Set to Identify Potentially Extreme Events



- **Unavailable Supply**
  - Each resource-specific risk model is evaluated at each interval (i.e., each hour) using the weather data for each 21-day period and the unavailable supply is estimated
  - Unavailable supply for all resources is aggregated across all intervals
- **Exceptional Demand**
  - In addition to estimating supply-side risk, demand-side risk is estimated based on a fixed demand threshold
  - Exceptional demand is estimated in each interval and aggregated across all intervals
  - Thresholds of 21 GW and 23 GW were established for screening of winter and summer events, respectively

Risk Screening Model: Searches Weather Data Set to Identify Potentially Extreme Events, cont.



- **System Risk** = aggregated unavailable supply + exceptional demand
- Sliding windows were applied in order to define the set of possible 21-day events
  - 21-day windows were shifted every 7 days
- The Risk Screening Model was used to select tail risk events for each study year; output was 1,470 high risk 21-day events (top ~4% of all possible 21-day events)

Analysis of Top 10 Events From Risk Screening Model Indicates Some Similarities Between 2027 and 2032

2027 Top 10 Unique* Events (of 1,470)

Rank	21-Day Event Start Date	Avg. System Risk (MW)	Model/SSP
1	Jan 22, 1961	9,160	IPSL/370
2	Feb 02, 1979	9,005	IPSL/370
3	Jan 15, 1961	8,899	IPSL/370
4	Jan 01, 1981	8,719	GFDL/126
5	Feb 14, 2015	8,714	IPSL/126
6	Jul 5, 2010	8,696	UKESM/370
7	Jul 13, 1979	8,685	UKESM/370
8	Jan 15, 1971	8,665	IPSL/370
9*	Jan 11, 1994	8,660	IPSL/370
10	Feb 09, 1979	8,656	IPSL/370

Analysis of Top 10 Unique Events

Based on a measure of the highest average system risk (MW):

- Top 10 events in both study years consistently demonstrate system risks associated with winter cold weather though summer events are also represented
- System risk increases slightly from 2027 to 2032 (note this is not a final study result, just an observation based on the risk screening)
- Significant overlap exists within events in target study years (see color-shaded pairs in each table)
- All but two* of the top ten unique events overlap across target study years, though system risk varies for each event from 2027 to 2032

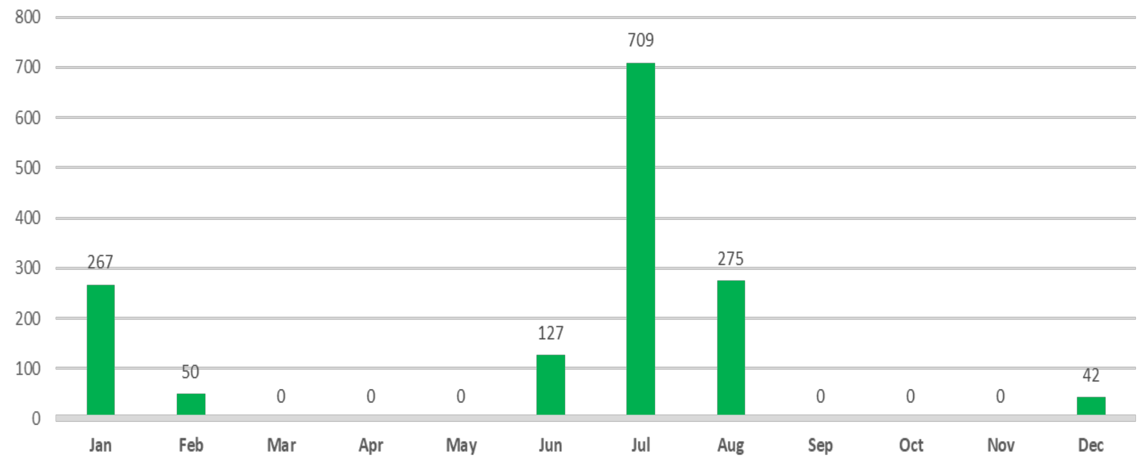
2032 Top 10 Unique* Events (of 1,470)

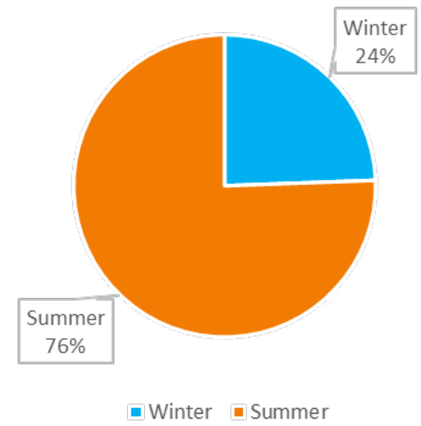
Rank	21-Day Event Start Date	Avg. System Risk (MW)	Model/SSP
1	Jan 22, 1961	9,272	IPSL/370
2	Feb 02, 1979	9,134	IPSL/370
3	Jan 15, 1961	9,011	IPSL/370
4	Jul 13, 1979	8,940	UKESM/370
5	Jul 5, 2010	8,898	UKESM/370
6*	Jul 28, 1988	8,806	UKESM/370
7	Feb 09, 1979	8,799	IPSL/370
8	Jan 15, 1971	8,796	IPSL/370
9	Jan 1, 1981	8,783	GFDL/126
10	Feb 14, 2015	8,780	IPSL/126

*the term "unique" is used to indicate that due to the use of multiple global climate models and SSPs there may be duplicate versions of the same 21-day event. For example, there are 5 versions of the Jan 22, 1961 event in the Top 10, each based on a unique climate model/SSP combination.

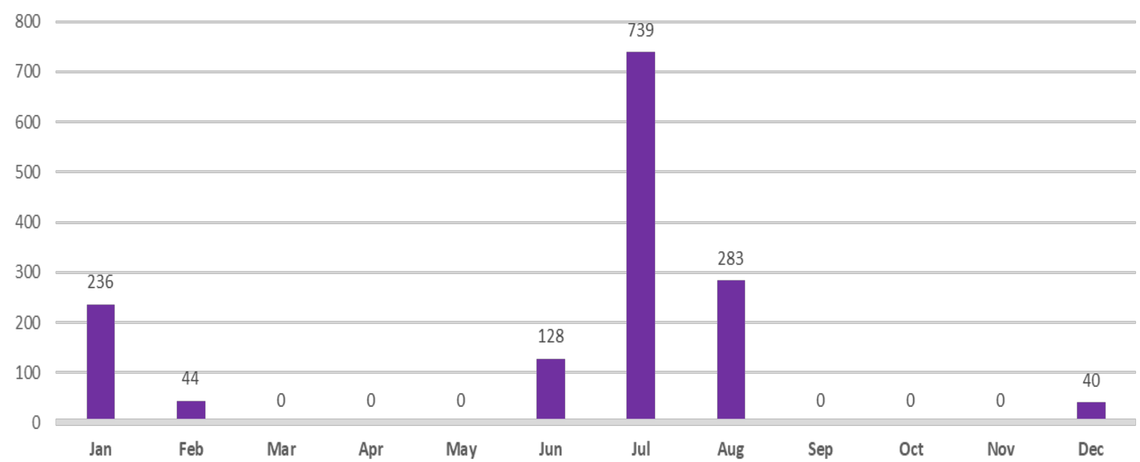
Top 10 Lists Highlight Winter Events, but Summer Events are Prevalent in Risk Screening Model Results

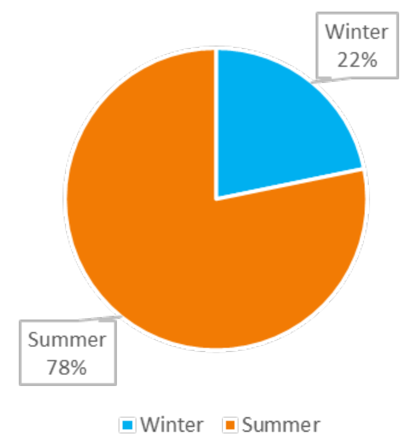
2027





2032



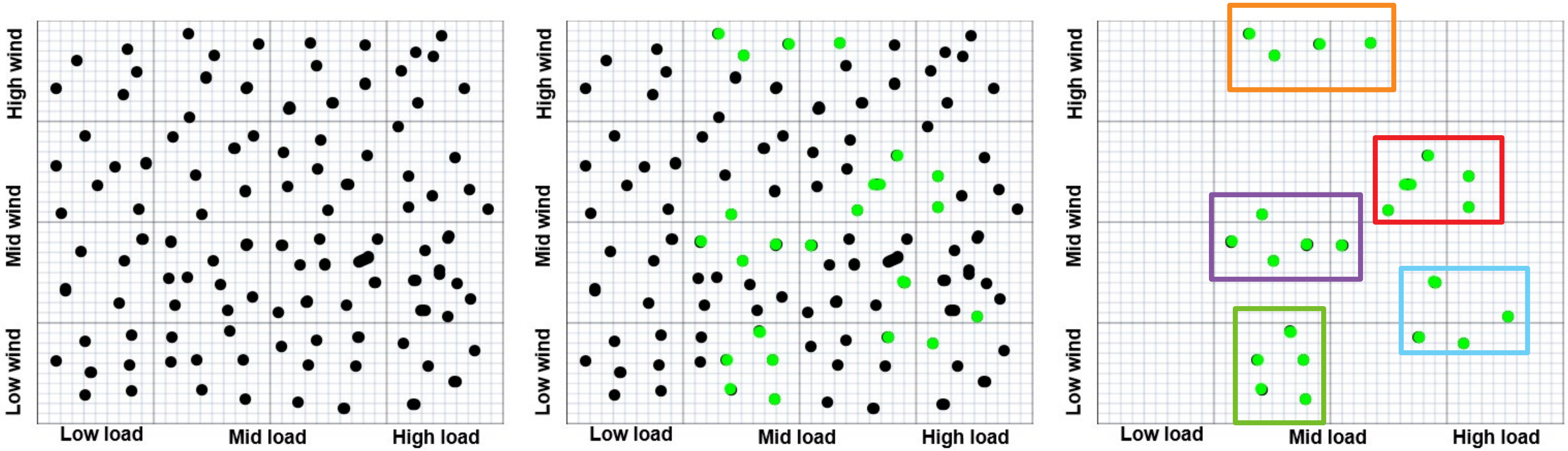


STEP 2: EVENT SELECTION METHODOLOGY

Overview of Event Selection Methodology

- Objective was to select a set of 21-day events that appear the most extreme to the future New England power system in terms of energy availability
  - The initial set of events is based on the output of the Risk Screening Model which determines system risk as aggregated unavailable supply plus exceptional demand
- Considerations in selecting events
  - Seek a representative set of 21-day events per target study year (2027, 2032)
  - Events should include a diverse set of risks; however, diversity is a secondary consideration to vulnerability
  - Select extreme cases representative of similar risks

Visual Depiction of Event Selection Methods



Initial Set of Events
37,440 21-day events per year of study *(as depicted by the* black dots *in figure above*)
52 21-day events/year x 720 versions of each study year = 37,440

Risk Screening Model

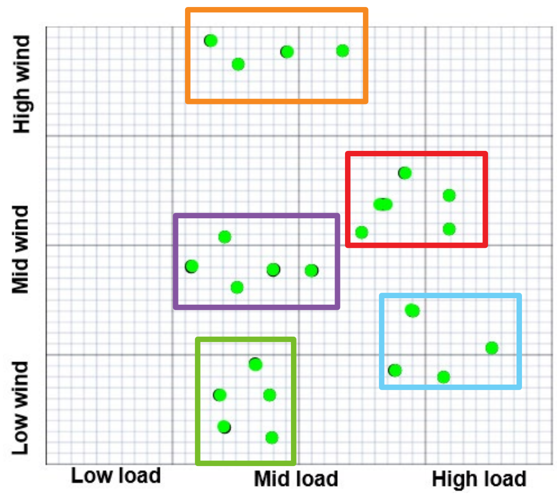
Select Highest Risk Events
1,497 events initially selected *(as depicted by the green dots in the figure above)*
(= top 21 events from each of 7 decades since 1950)

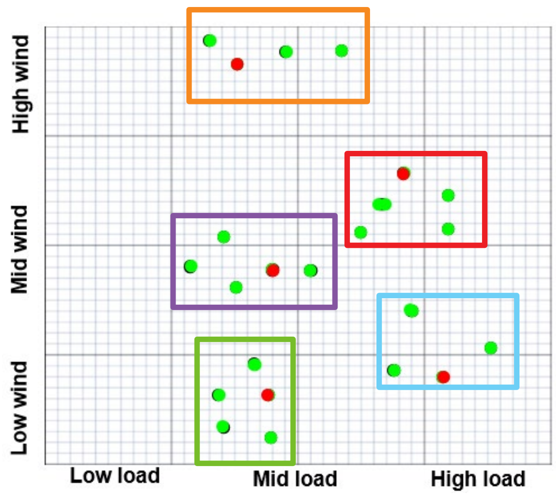
Clustering Algorithm

Group Similar Events
Use a clustering algorithm to group high risk events into multiple clusters
The clustering algorithm also determines the number of clusters

Note that these figures are intended only to represent event selection process and are not intended to convey actual results

Visual Depiction of Event Selection Methods, cont.





Group Similar Events

Use a clustering algorithm to group high risk events into multiple clusters

The clustering algorithm also determines the number of clusters

Select Representative Events

Select Events

From each group (or cluster), select one or more events (*as depicted by the red dots in the figure above)*

that represent the set of events within a cluster

Note that these figures are intended only to represent event selection process and are not intended to convey actual results

Description of Clustering Method

- To avoid studying very similar events, the K-means clustering technique was used to group similar events into clusters
- The K-means/K-medoids approach is a machine-learning technique that involves the grouping of data points
- Factors used to differentiate events
  - System Factors
    - Average system risk, maximum system risk, total load
  - Common Mode Factors
    - Average temperature, extreme temperature
  - Renewable Factors
    - Average irradiance, number of dark days and/or calm days, wind speed
  - Precipitation (including snow) was evaluated but later excluded as they reinforced load and temperature dimensions in Principal Component Analysis (PCA)
- The outcome of the clustering process was five "clusters" (or groups) of events for each study year, each with unique operational challenges

Summary of Clustering Outcomes, 2027

Cluster Name	# of Events in Cluster (of 1,470)	Brief Representative Description of Events in Cluster	Avg. Temp (F)	Avg. System Risk (MW)	% of Days with Extreme Cold/Hot Temps (<10 F, or >85 F)	Avg. Max Load (GW)	% of Days with Low Wind (<4 m/s)	% of Days with Low Irr. (<200 W/m^2)
Winter 1 (W1)	129	Long-Duration Extreme Cold Wave(s), Low Winds and Very Low Solar	**17.2**	**8,288**	**30.8%**	**20.9**	60.4%	99.6%
Winter 2 (W2)	230	Short to Mid-Duration Extreme Cold Snap(s), Low Winds and Very Low Solar	19.9	7,588	13.9%	20.6	**68.3%**	**99.8%**
Summer 1 (S1)	234	Long-Duration Heat Wave, Highest Summer Loads, Low Winds	**78.8**	**7,936**	**8.2%**	**23.9**	96.4	20.0%
Summer 2 (S2)	503	Short to Mid-Duration Heat Wave, High Summer Loads, Low Winds and Low Solar	76.3	7,588	2.0%	22.8	97.0	22.8%
Summer 3 (S3)	374	Moderate Summer Temps, Avg. Summer Loads, Very Low Winds and Very Low Solar	73.9	7,421	0.2%	21.2	**98.5%**	**24.2%**

*Bold and colored (**blue** or **red**) text indicates the cluster in which each variable is the most extreme (largest or smallest, as applicable) value within the same season (winter or summer)

Summary of Clustering Outcomes, 2032

Cluster Name	# of Events in Cluster (of 1,470)	Brief Representative Description of Events in Cluster	Avg. Temp (F)	Avg. System Risk (MW)	% of Days with Extreme Cold/Hot Temps (<10 F, or >85 F)	Avg. Max Load (GW)	% of Days with Low Wind (<4 m/s)	% of Days with Low Irr. (<200 W/m²)
Winter 1 (W1)	125	Long-Duration Extreme Cold Wave(s), Low Winds and Very Low Solar	**17.8**	**8,298**	**28.5%**	**23.4**	60.2%	99.6%
Winter 2 (W2)	195	Short to Mid-Duration Extreme Cold Snap(s), Low Winds and Very Low Solar	20.9	7,606	12.6%	23.1	**68.9%**	**99.8%**
Summer 1 (S1)	127	Long-Duration Heat Wave, Highest Summer Loads, Low Winds	**80.2**	**8,167**	**17.8%**	**25.4**	96.0%	17.9%
Summer 2 (S2)	441	Short to Mid-Duration Heat Wave, High Summer Loads, Low Winds and Low Solar	77.6	7,800	3.8%	23.9	96.9%	22.3%
Summer 3 (S3)	582	Moderate Summer Temps, Avg. Summer Loads, Very Low Winds and Very Low Solar	75.0	7,469	0.7%	22.3	**97.7%**	**24.1%**

*Bold and colored (**blue** or **red**) text indicates the cluster in which each variable is the most extreme (largest or smallest, as applicable) value within the same season (winter or summer)

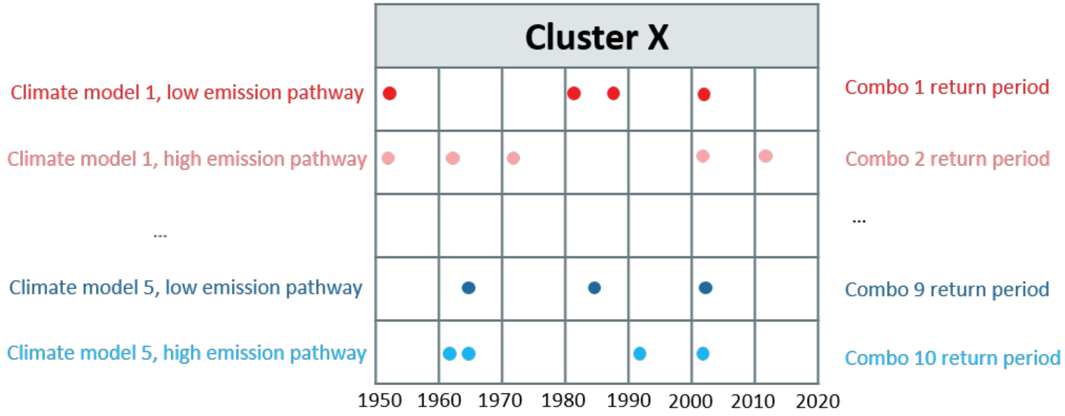
STEP 2: RETURN PERIOD CALCULATION

The Return Period of Weather Events Was Estimated at the Cluster Level

- A return period is the expected interval between event recurrences
  - A 1-in-5 year event means the average time between similar events is 10 years over a long period of time
  - A 1-in-5 year event has a probability of 20% of occurring in any one year
- Return period is not a guarantee of when an event would occur, but it is a representative figure to show the rareness and extremeness of an event
- The return period of events are estimated at the cluster level
  - Extreme events in the same clusters are considered to have similar weather attributes
  - Cluster-level return period estimation improves the number of observations of similar extreme events

Method Used to Estimate Return Periods for Weather Events

- For each cluster return period estimates are developed for each climate model and emission pathway combination
  - There are 5 climate models and 2 climate scenarios
  - The return period of each combination is equal to the average of elapsed time between two consecutive events in the combination



Each dot in the figure above represents a 21-day event in Cluster X

- Return period consensus ranges are developed based upon the smallest range that 70% of combinations can agree on

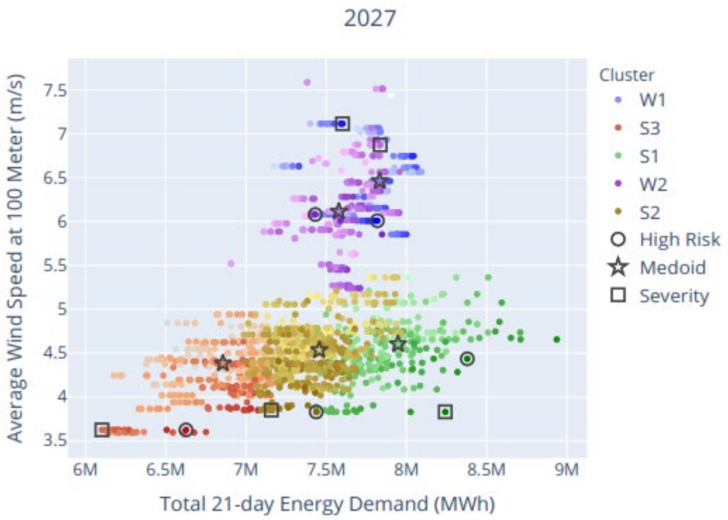
Estimated Return Periods of 2027 and 2032 Event Clusters

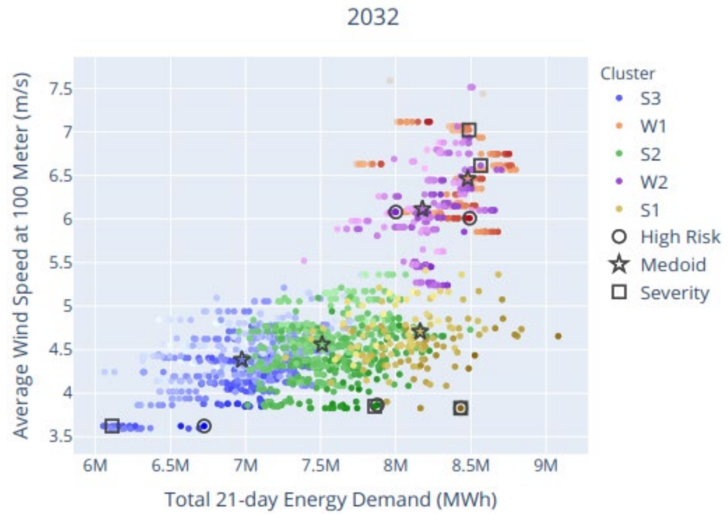
Cluster	Return Period (2027)	Return Period (2032)
Winter Cluster 1	8 - 10 years	3 - 7 years
Winter Cluster 2	3 - 5 years	2 - 5 years
Summer Cluster 1	2.5 - 12 years	36 - 72 years
Summer Cluster 2	2 - 3 years	1 - 2 years
Summer Cluster 3	2 - 2.5 years	1 - 1.5 year

STEP 2: REVIEW OF SELECTED EVENTS

Three Events Were Selected From Each Cluster

- There is some variability in the weather characteristics within each cluster
- From each cluster, in order to balance the tradeoff between extreme risk and representation of the entire cluster, three events have been selected (*see* next 2 slides)
- One event selected based on the highest average system risk
  - Represents the extreme risk associated with the cluster
- One event selected based on the highest severity index
  - Reflect compounding risk under prolonged durations
- One event selected based on the medoid
  - It is the event in the center of the cluster and therefore most representative of the entire cluster of events





*The visual depictions on this slide include <u>only two variables</u>, total 21-day energy demand (MWh) and average wind speed at 100 meters (m/s). Notably, the clustering algorithm takes many additional variables into consideration. **This exhibit is intended only to visually reinforce the clustering methodology.**

Summary of Winter Events Selected From Each Cluster

2027 Target Year				2032 Target Year			
Cluster	Event Start Date***	Avg. System Risk (MW)	Model/ SSP	Cluster	Event Start Date***	Avg. System Risk (MW)	Model/ SSP
W1	Jan 22, 1961*	9,160	IPSL/370	W1	Jan 22, 1961*	9,272	IPSL/370
	Feb 2, 1979	9,005	IPSL/370		Jan 12, 2004	8,424	IPSL/370
	Jan 15, 1971**	8,306	MRI/370		Jan 15, 1971**	8,277	MRI/370
W2	Feb 14, 2015*	8,178	UKESM/ 126	W2	Feb 14, 2015*	8,116	UKESM/ 126
	Jan 14, 1982	7,697	IPSL/370		Jan 7, 1982	7,798	UKESM/ 126
	Jan 11, 1970**	7,570	GFDL/126		Jan 11, 1970**	7,588	GFDL/126

*Two Winter Instances of Overlap Between Target Years For Events Selected Based on Highest Avg. System Risk;
**Two Winter Instances of Overlap Between Target Years For Events Selected based on Medoid;
***For each cluster (W1, W2, etc.) the first event listed is the event selected based on highest avg. system risk, the second event is based on the highest severity index, and the third event is based on medoid

Summary of Summer Events Selected From Each Cluster

2027 Target Year				2032 Target Year			
Cluster	Event Start Date***	Avg. System Risk (MW)	Model/ SSP	Cluster	Event Start Date***	Avg. System Risk (MW)	Model/ SSP
S1	Jul 05, 2010	8,696	UKESM/ 370	S1	Jul 13, 1979	8,940	UKESM/ 370
	Jul 13, 1979**	8,685	UKESM/370		Jul 13, 1979**	8,940	UKESM/370
	Jul 25, 1995	7,839	MRI/370		Jul 05, 1994	8,214	UKESM/370
S2	Jul 13, 1979	8,023	GFDL/126	S2	Aug 02, 1984	8,460	UKESM/ 370
	Jul 26, 1984	7,858	MPI/370		Jul 26, 1984	8,367	UKESM/370
	Aug 17, 1953	7,549	IPSL/126		Jul 11, 1995	7,744	IPSL/370
S3	Jul 28, 2008*	7,917	UKESM/ 370	S3	Jul 28, 2008*	8,001	UKESM/ 370
	Jul 28, 2008	7,612	MPI/126		Jul 28, 2008	7,627	IPSL/126
	Jul 19, 1984	7,419	IPSL/126		Aug 06, 2001	7,441	MPI/126

*One Summer Instances of Overlap Between Target Years For Events Selected Based on Highest Avg. System Risk;
**One Summer Instances of Overlap Between Target Years For Events Selected based on Severity Index;
***For each cluster (W1, W2, etc.) the first event listed is the event selected based on highest avg. system risk, the second event is based on the highest severity index and the third event is based on medoid

STEP 2: SCENARIO GENERATION

Overview of Step 2 Power System Scenario Generation

- Following the selection of 21-day events for study, a complete set of cases and their probabilities were developed as an input to the 21-day energy adequacy studies in Step 3
- The objective of the scenario generation step was to develop a range of possible cases that incorporate the following uncertainties and their likelihoods:
  - Indirect-weather related uncertainties that may occur during the event and may influence resource (or energy) availability, and
  - Random forced outages and maintenance outages
- Scenario trees were developed to capture various uncertainties
- Multiple combinations of possible scenarios associated with New England Clean Energy Connect (NECEC) and Everett Marine Terminal (EMT) were also considered in development of possible cases for study in Step 3

Scenarios for Each Study Year

- Each 21-day event is studied under four scenarios; each scenario reflects a combination of statuses of two key variables – the EMT and the NECEC facility
  - scenarios have not been assigned a probability of occurrence

	NECEC **in-service**	NECEC **not in-service**
EMT **in-service**	With NECEC, With EMT	No NECEC, With EMT
EMT **not in-service**	With NECEC, No EMT	No NECEC, No EMT
	Max imports 5,625 MW/hr	**Max imports 4,545 MW/hr**

- Scenarios with NECEC in-service allow up to an additional 1,080 MW/h of max imports from Hydro-Québec

Scenarios for Each Study Year, cont.

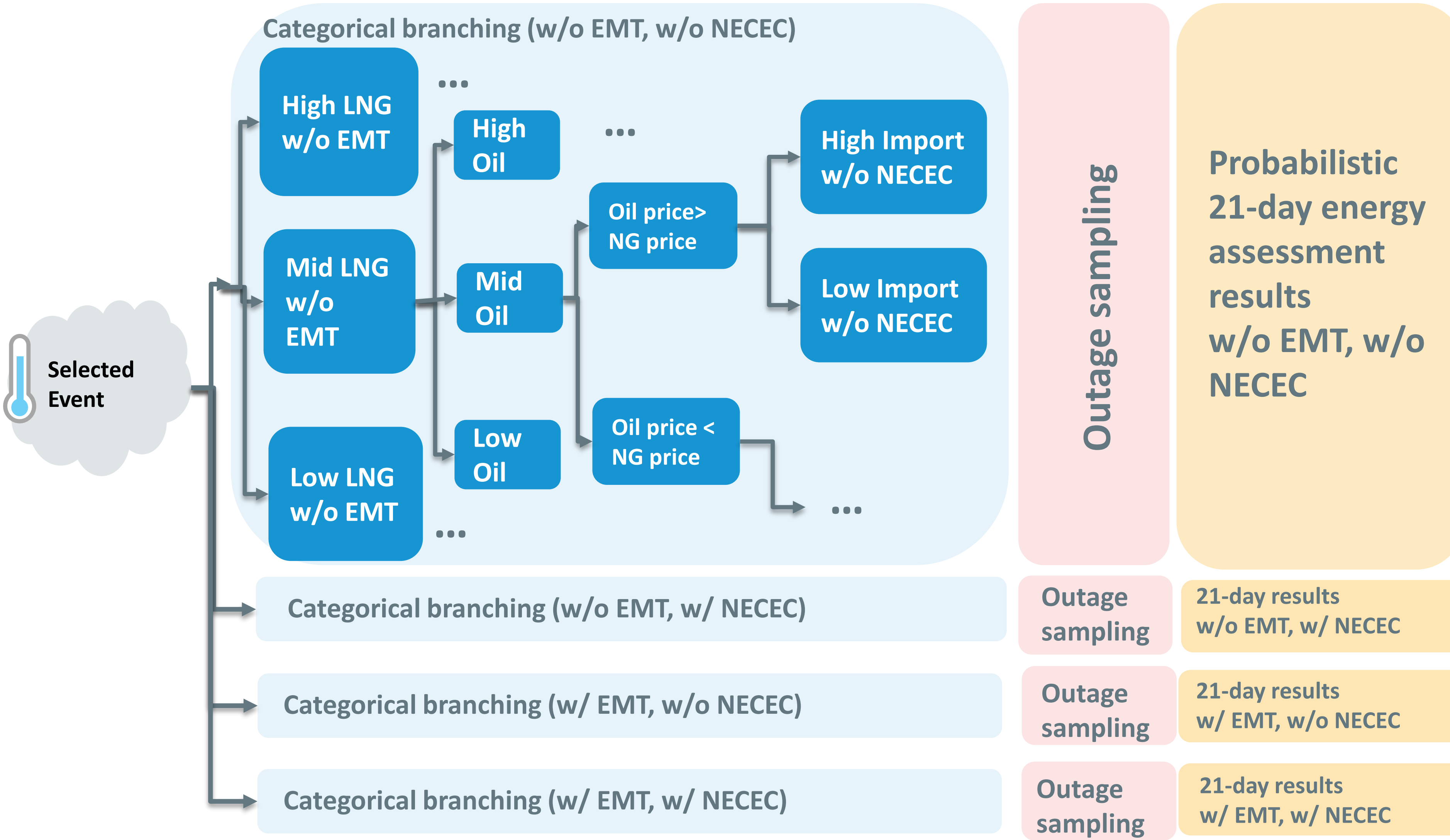
	NECEC **in-service**	NECEC <u>**not**</u> **in-service**	
EMT **in-service**	With NECEC, With EMT	No NECEC, With EMT	**Max inj. 1.2 Bcf/d**
EMT <u>**not**</u> **in-service**	With NECEC, No EMT	No NECEC, No EMT	**Max inj. 0.8 Bcf/d**

- Scenarios with EMT in-service allow an additional 0.4 Bcf/day of maximum LNG injection to pipelines
  - Study results with/without EMT are highly dependent on the characteristics of a given event, including the timing of the highest energy demands, starting LNG inventories, and timing of LNG replenishment
  - Higher rates of LNG injection (i.e., LNG injection rates with EMT) may deplete LNG inventories prior to replenishment, leading to larger energy shortfalls in some cases with EMT than in similar cases without EMT

Cases for Each Scenario

- For each winter event, each of the four scenarios is modeled with 720 “cases” which are different combinations of the following uncertainties, each with an assigned probability of occurrence
  - LNG inventory: High, medium, low
  - Fuel oil inventory: High, medium, low
  - Imports: High, low
  - Fuel prices: natural gas more or less expensive than oil
  - Generator forced outages: 20 samples
- For each summer event, each of the four scenarios is modeled with 40 “cases” which are different combinations of the following uncertainties, each with an assigned probability of occurrence
  - Imports: High, low
  - Generator forced outages: 20 samples
  - LNG, fuel-oil, and fuel price uncertainties have only one possible value in summer cases
    - LNG inventory is high
    - Fuel oil inventory is high
    - Natural gas is less expensive than oil

Scenario Trees are Developed to Capture Various Uncertainties



STEP 2: SCENARIO GENERATION

Modeling of imports

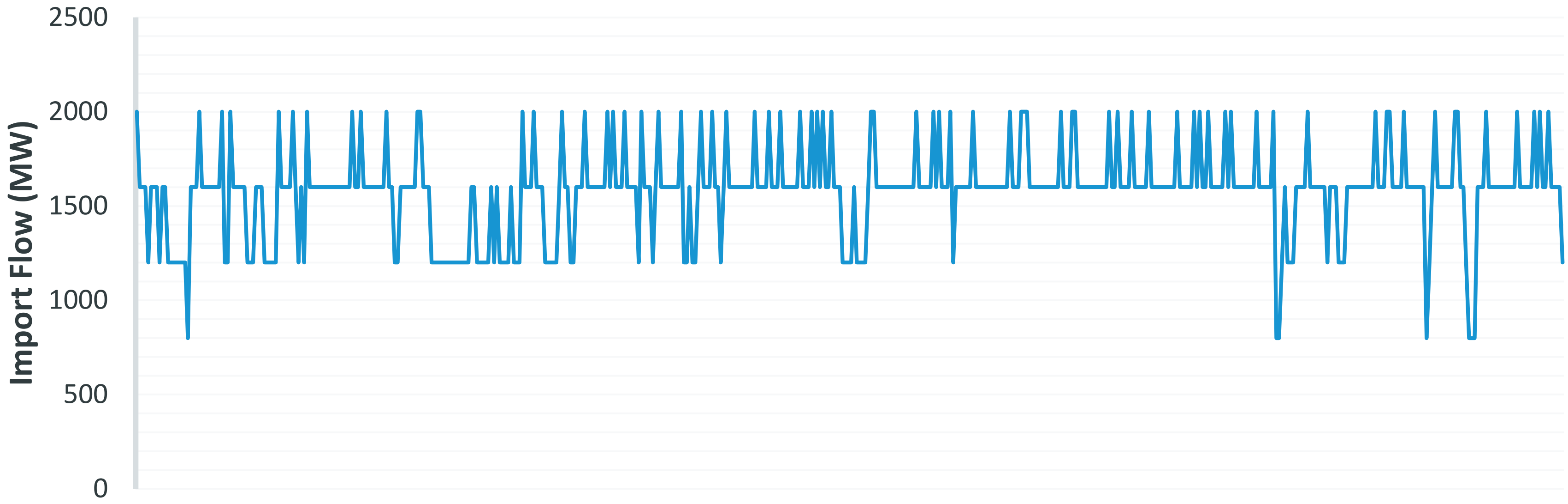
Considerations For Modeling of Imports

- Analysis of historical interchange levels demonstrates a poor ability to forecast imports, particularly during extreme events; an additional consideration is that neighboring systems also changing over time
- Import levels incorporated into scenarios for study in Step 3 need to be realistic and must also stress test the system during the event; this implies a need for a categorical branching approach
- Consideration has also been given to the uncertainties associated with the development of NECEC

Approach for Modeling of Imports

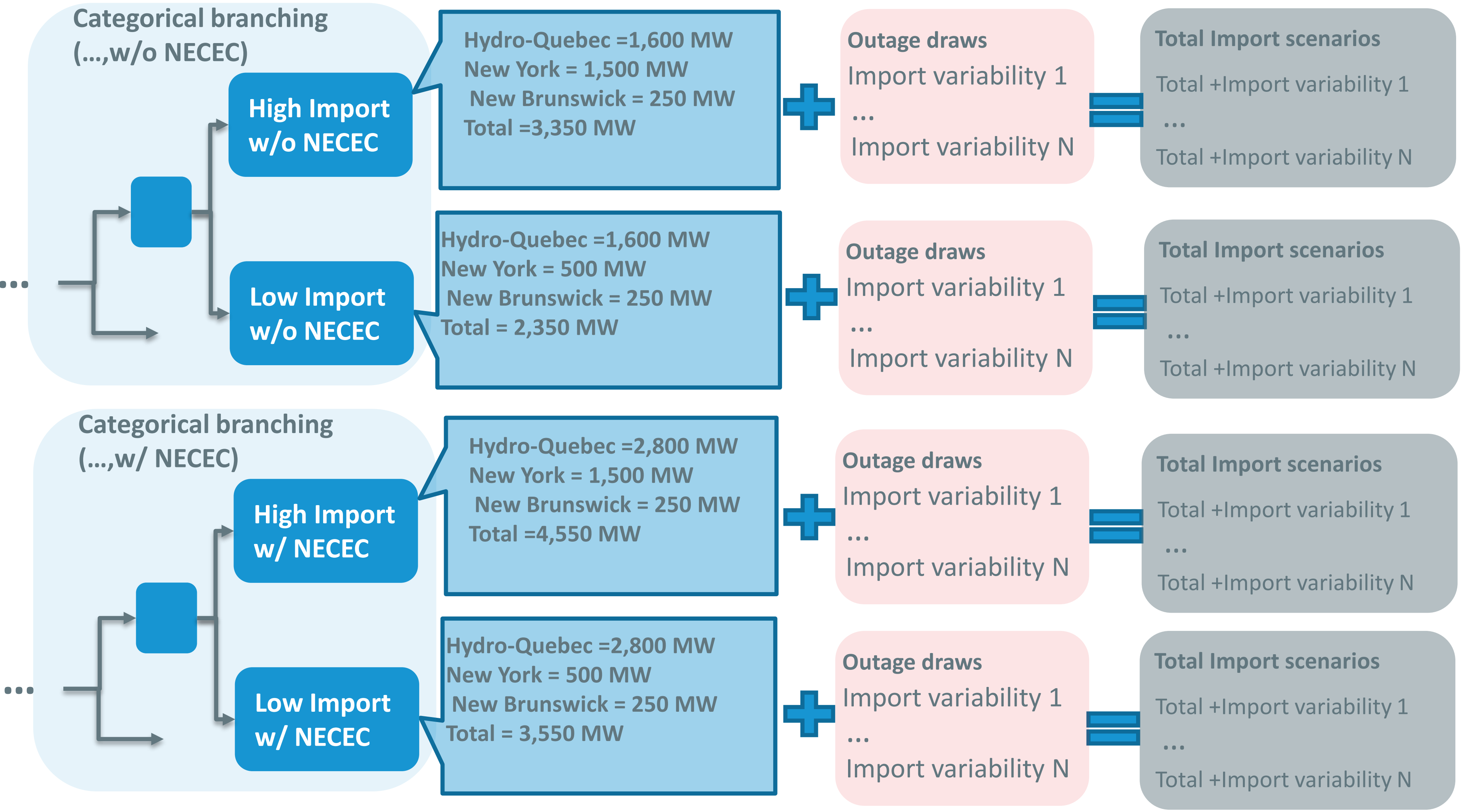
- A combination of import levels and a probabilistic model for flow variability are utilized
- Average import levels
  - Hydro-Quebec -> Two import levels (vary based on NECEC scenarios)
    - With NECEC: 2,800 MW median import
    - Without NECEC: 1,600 MW median import
  - New York -> Two categorical branches of imports
    - 500 MW median import
    - 1,500 MW median import
  - New Brunswick –> One categorical branch of imports
    - 250 MW median import
- Probabilistic model
  - An import variance model has been developed to create fluctuation in import flows, aligning with historical variability

A Probabilistic Model Enables Variability In Imports Across the 21-Day Period



- Addition of variability enables periods of lower imports to be assessed as part of scenarios in Step 3
- Samples are generated using same principles as forced outage draws – Markov Chain Monte Carlo (see more details later in "*Step 2: Scenario Generation - Modeling of generator maintenance and forced outages*" subsection)
- Samples are drawn alongside generator forced outages and included in forced outage draws associated with each scenario

Examples of Approach for Modeling of Imports



STEP2: SCENARIO GENERATION

Modeling of stored fuel inventory and fuel prices

Considerations For Modeling of Stored Fuel Inventories

- ISO's 21-day energy assessment simulator includes extensive fuel inventory and fuel switching logic linked to generation dispatch
- Key inputs into scenarios for study in Step 3 include stored fuel inventory available at the start of a 21-day period (i.e. the event) and any fuel replenishment during the 21-day period
- Detailed real-time fuel inventory information is available in operational timeframe but an alternative approach is needed for longer-term studies like this study
- EPRI developed a method that provides estimated stored fuel inventories and replenishment when studying scenarios in Step 3; LNG model leverages a vendor-developed LNG model

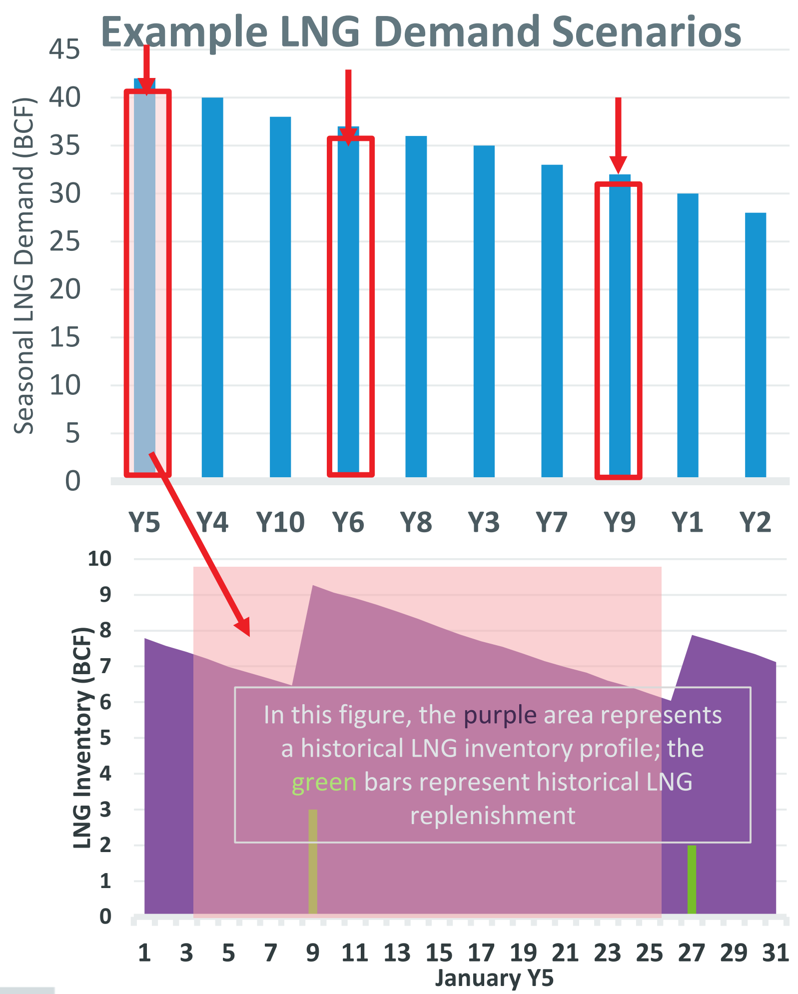
Approach for LNG Inventory & Replenishment Modeling

- Three potential levels for LNG inventory based on seasonal forecast values
  – High LNG demand season -> likely higher starting inventories
  – Medium LNG demand season
  – Low LNG demand season -> likely lower starting inventories
- LNG replenishment schedule in line with observed historical deliveries to the region’s three LNG facilities (Saint John, EMT, and Excelerate)
- LNG-related inputs to Scenario Generation include historical LNG inventories by winter season and three seasonal LNG demand forecasts for 2027 and 2032 with associated likelihoods

Approach for LNG Inventory & Replenishment Modeling, cont.

- Modeling Approach
  - Aggregated historical LNG inventories by winter season (winter 2013/14 to present)
    - Reconstructed regional daily aggregate LNG inventory
    - Recorded LNG cargo arrivals
  - For each possible starting LNG inventory level (High, Med, Low):
    - Associated a historical LNG profile (i.e. LNG profile from a past winter season) to each of the three seasonal LNG demand forecasts; feasibility is determined by the seasonal LNG demand + end of season inventory
  - For each event being studied,
    - Set the starting LNG inventory to align with the inventories observed at the start date of the event (by calendar day)
    - Resupply cargo schedule based on historical arrivals

Example (illustrative values)



Approach for LNG Inventory & Replenishment Modeling, cont.

- LNG-related outputs for use In Step 3 studies include starting LNG inventories for each case and an LNG replenishment profile
- Under the “without EMT” scenario, LNG deliveries and sendouts to EMT are instead sent to the Saint John LNG facility

Approach for Fuel Oil Inventory Modeling

- Fuel-oil inputs to Scenario Generation are historical fuel oil inventories, by generating stations
- Modeling approach:
  - Aggregate fuel-oil inventory across generating stations and week number, by type (residual fuel oil and distillate fuel oil)
  - For each week determine inventory percentiles:
    - P83 (High scenario)
    - P50 (Med scenario)
    - P17 (Low scenario)
  - For each event being studied:
    - Determine week number associated with the event
    - Produce 3 (High, Med, Low) inventory scenarios
- Fuel-oil outputs for use in Step 3 studies:
  - Three fuel-oil inventory scenarios based on week number with equi-probable likelihood
    - Aggregate fuel oil amounts are distributed to specific generating stations by weighting factors

Approach for Fuel Price Modeling

- Fuel price-related inputs to Scenario Generation include historical fuel oil, distillate, natural gas prices and typical fuel switching threshold
- Modelling approach:
  - For each week, determine the likelihood that the natural gas price exceeds the threshold price
  - Develop two price profiles
    - Profile A: natural gas price < threshold
    - Profile B: natural gas price > threshold at peak
- Output for use in Step 3 studies:
  - Two profiles with associated likelihoods of occurrence

STEP 2: SCENARIO GENERATION

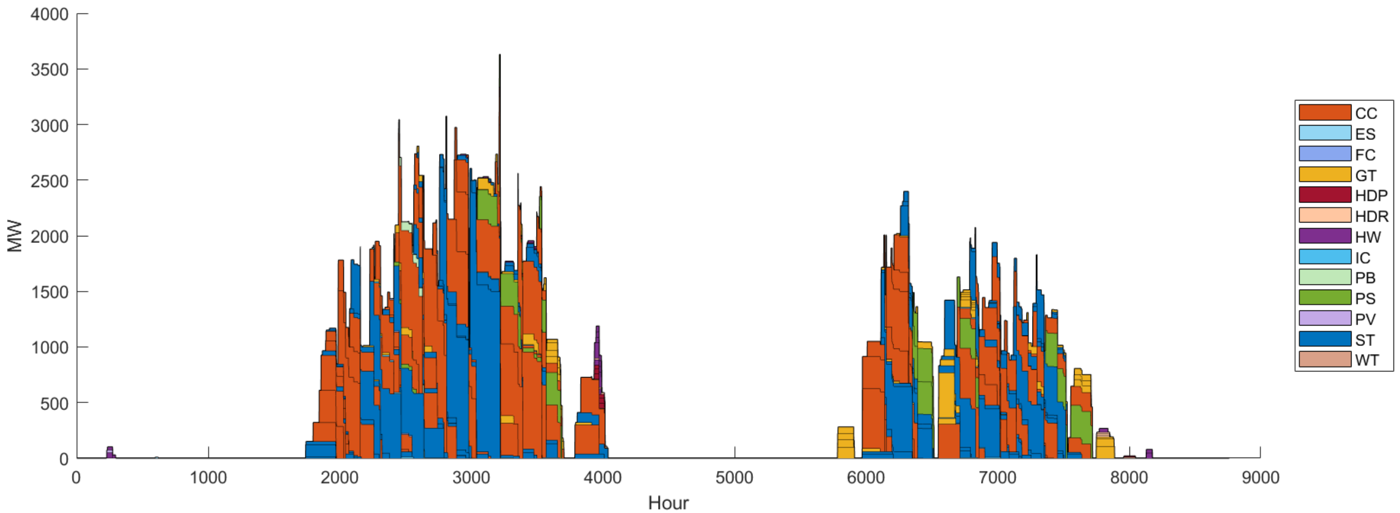
Modeling of generator maintenance and forced outages

Considerations for Generator Maintenance Modeling

- Detailed real-time maintenance schedules are available in the operational time frame but an alternative approach is needed for longer-term studies
- Many resource adequacy tools implicitly schedule maintenance based on heuristic approaches to reduce system risk
- EPRI developed a method that provides a realistic generator maintenance forecast when studying scenarios in Step 3

Approach for Generator Maintenance Modeling

- **Inputs to Scenario Generation**
  - Historical maintenance outages by month and by unit type (combined cycle, gas turbine, nuclear, etc.)
- **Outputs For Use In Step 3:**
  - Maintenance profile by year
- **Modeling Method:**
  - Generator maintenance is scheduled to avoid contributing to peak load scarcity
  - Schedule longest duration outages first, shortest last



Review of Generator Forced Outage Modeling Techniques

Traditional Forced Outage Modeling

- Since the mid-20th century probabilistic resource adequacy methods have incorporated forced outage modeling as a stochastic variable
- Traditionally, RA studies assume outages to be independent and uncorrelated from each other with constant failure rate independent of:
  - Weather events (Hurricanes, Storms, …)
  - Temperature effect (Seasonal effect)
  - Ageing effects
  - Capacity/ Size
  - Start-up cycles
  - High load

Weather-Dependent Forced Outage Modeling

- Historical forced outage data shows that weather conditions can increase failure probabilities of power units
- Recent events highlight the importance of accurately modeling weather dependent forced outages
- Recent research* proposes a model that considers temperature dependent force outage modeling using logistic regression to predict failures and recoveries transition states

**'A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence'. Authors: Sinnott Murphy, Fallaw Sowellb, Jay Apt*

Considerations for Probabilistic Modeling of Generator Forced Outages

- EPRI developed a detailed modeling method capable of creating samples of generator failure and repair under extreme weather conditions being studied
- Two options were considered

Options	Pros	Cons
Seasonal	Simple to implement	Does not capture behavior at extremes
Weather dependent	Captures behaviors at extremes and in each interval	Limited data to train models

Considerations for Probabilistic Modeling of Generator Forced Outages, cont.

- Weather-dependent option selected despite data shortcomings; ISO and NERC GADS anonymized unit level data was used to train models
- Temperature-dependent forced outage rate model developed for each unit type by size (MW), physical location (state), and age
- Failure rate varies based on conditions at the weather station associated with the unit -> not seasonal or annual average

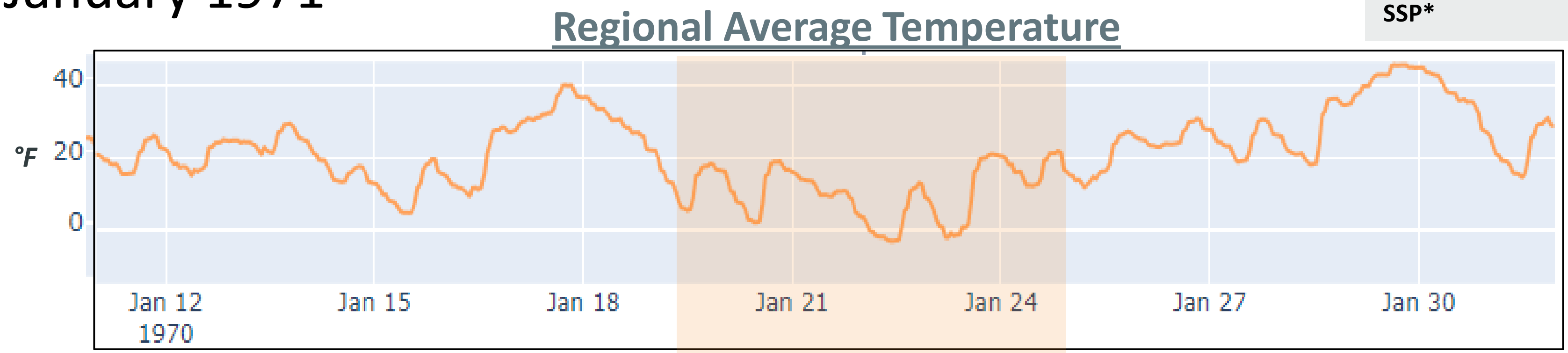
Considerations for Probabilistic Modeling of Generator Forced Outages, cont.

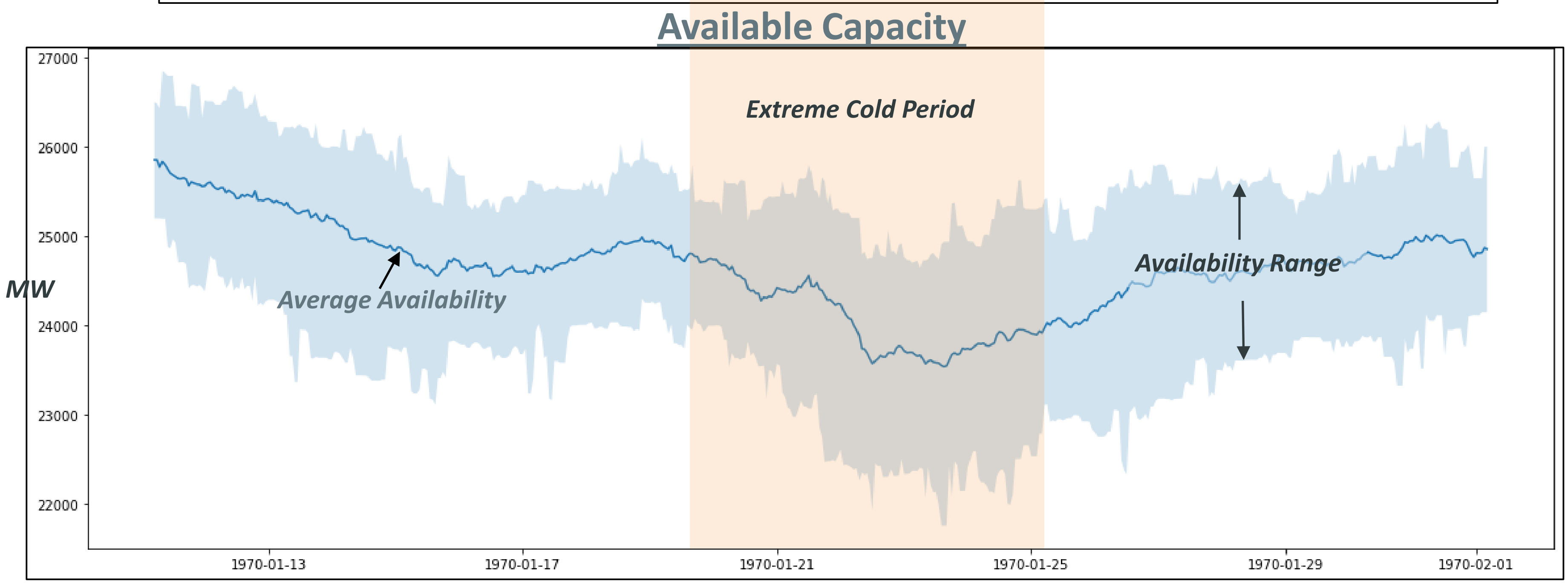
- Probabilistic simulation-based approach that implements Monte Carlo draws was utilized
- Requires multiple samples to be analyzed to converge on expected value statistics; this approach is similar to resource adequacy studies
- For each scenario, 20 outage samples are generated
  - Outage samples share equal probabilities

Example Forced Outage Profiles for Event

January 1971

Event	W1
Target	2032
Climate Model	GFDL
SSP*	126





MTTR (hours) and FOR (%)

MTTR all_state all_tech	**77.4**
FOR all_state all_tech	**16.9**

*SSP is shared socio-economic pathway

Summary of Probabilistic Modeling of Generator Forced Outages

- Model implements best-in-class temperature sensitive forced outage modeling approach using a very extensive data set
- Significant and meaningful reduction in generator performance is observed at very cold temperatures
- EPRI's detailed model for developing generator forced outage samples for each event enables the study of a wide range of potential outage conditions during extreme weather events

Probabilities of Uncertainties As Used in 2027 and 2032 Events

- Probabilities have been determined for various uncertainties including LNG inventory, oil inventory, imports, and fuel prices
- Winter event probabilities - the table below describes probabilities for various levels of uncertainties as used in studies of winter events
  - "low" fuel price means that natural gas price is greater than the oil price
  - Import probabilities vary slightly by the case being studied

Winter Events (2027 and 2032)									
LNG Inventory			Oil Inventory			Imports		Fuel Price	
Low	Med	High	Low	Med	High	Low	High	Low	High
0.3%	14.1%	85.6%	33.3%	33.3%	33.3%	11-14%	86-89%	1%	99%

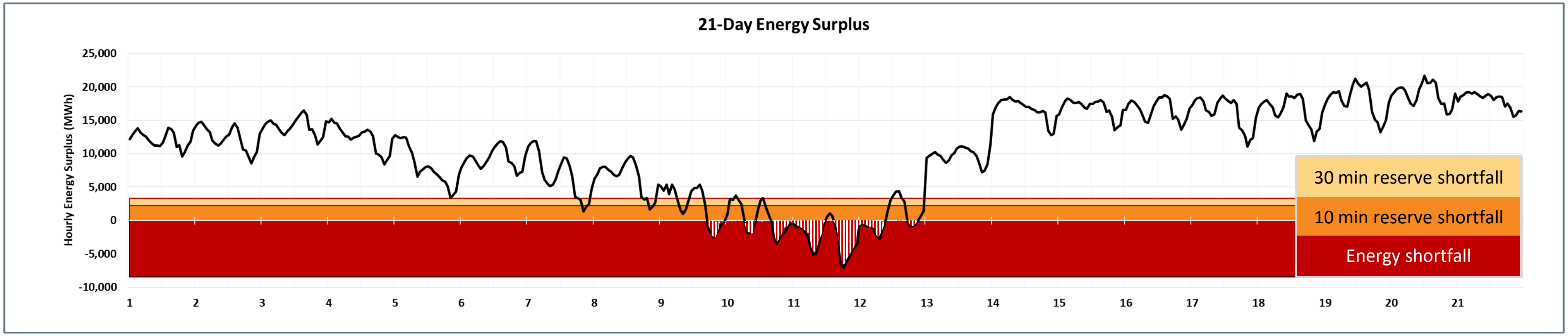
- Summer event probabilities - LNG inventory, oil inventory, and fuel price uncertainties only have one possible value in summer event studies therefore no probabilities are assigned
  - Probabilities have been determined for low and high imports; probability of low imports ranges from 21-29%, high imports range from 71-79%
- Forced outage samples are assumed to have equal probabilities

STEP 3 – ENERGY ASSESSMENTS

Purpose of 21-Day Energy Assessment

- ISO-NE utilizes the 21-Day Energy Assessment to forecast potential energy shortfalls across a 21-day period
  - Since Winter 2018/19, this analysis has been performed on a weekly basis during the winter months, bi-weekly otherwise
  - Results of the analysis are made publicly available on ISO-NE website, including the declaration of Energy Alerts and Energy Emergencies
  - Situational awareness provided by the analysis allows ISO-NE and stakeholders to make informed decisions in advance of any forecasted energy shortfalls
- The 21-Day Energy Assessment is the workhorse of Step 3

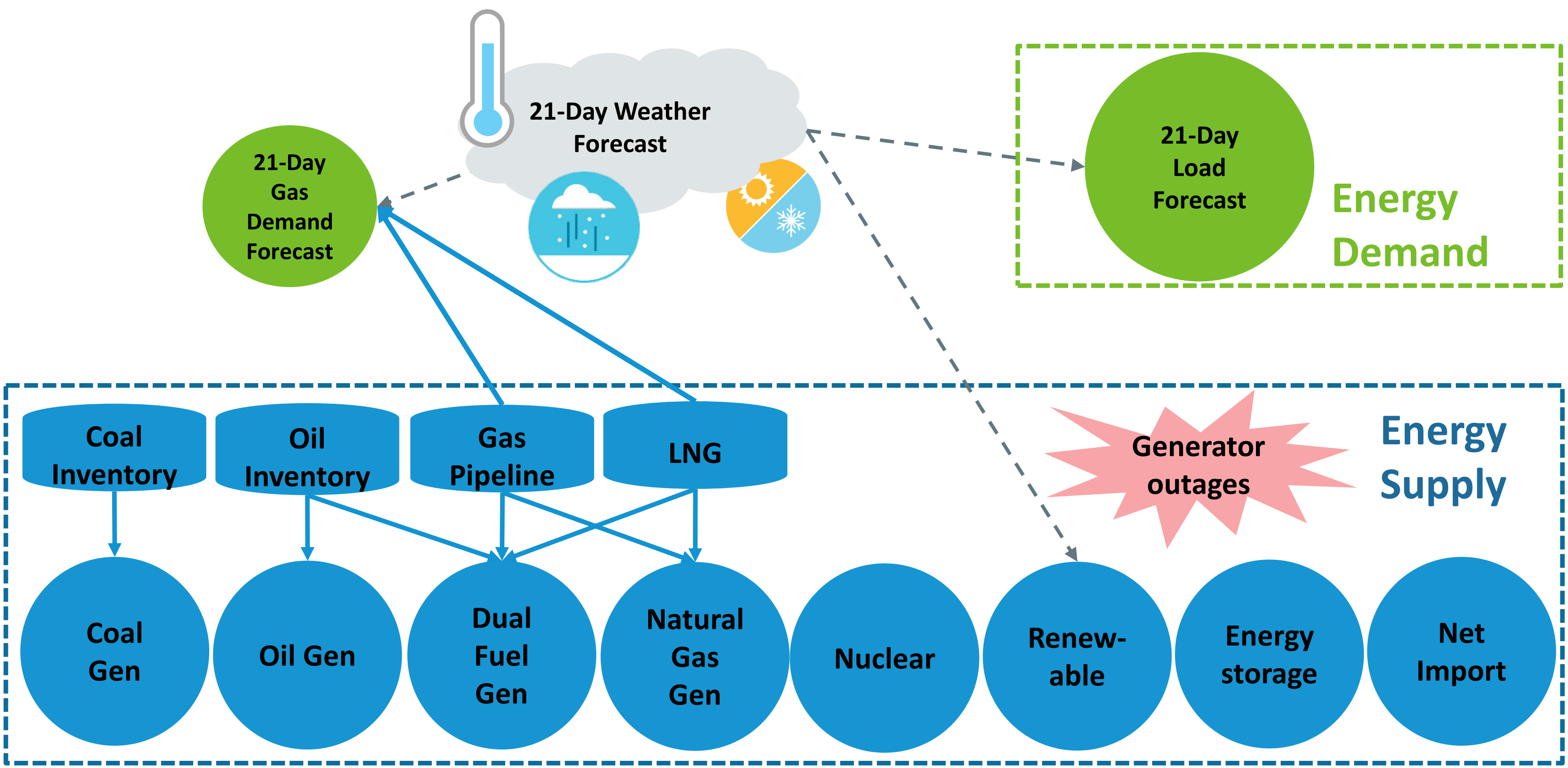
21-Day Energy Assessment Calculates Energy Surplus



*The figure above is an example illustration of a 21-day energy assessment forecast

- For each case, energy assessment results include:
  - Energy surplus (black curve)
  - Energy shortfall (red/white striped area): quantity in MWh and duration
  - Reserve shortfalls (black curve in yellow/orange): quantity in MWh and duration
- For each scenario, energy assessment results are a statistical summary across all 720 cases within scenario:
  - “Expected” energy shortfall = probability-weighted average across cases
  - “Worst-case” energy shortfall = case with highest energy shortfall quantity

Energy Surplus = Energy Supply – Energy Demand



Key Features of the 21-Day Energy Assessment

- Utilizes an economic dispatch approach
  - Generators are dispatched to meet load based on economic merit order
  - Energy and reserves are co-optimized
  - Dual fuel generators switch between natural gas and oil depending on fuel prices
  - Hourly granularity
- Manages fuel inventory
  - Dispatch capability of fossil fuel units is constrained by physical fuel storage
  - Coal, oil, pipeline gas, and LNG inventory is tracked hour-by-hour
- Performs efficiently
  - Assessment utilizes a JAVA-based engine and a state-of-the-art CPLEX optimization solver

21-Day Energy Assessment Assumptions

- Some resource types are modeled discretely (*i.e.*, at the unit level) for more accurate fuel inventory management
  - Oil, natural gas (NG), dual fuel, coal, nuclear, pumped storage hydro
- Other resource types are aggregated at the regional level for modeling simplicity
  - On-shore wind
  - Off-shore wind
  - Utility-scale PV
  - Batteries
  - Net imports
  - Demand response
- Transmission and generator ramping constraints are not considered
- Commitment-related costs and intertemporal constraints are not included
- Additional information on 21-day energy assessment can be found in the *April 19, 2023 NEPOOL Reliability Committee meeting*

The Connection Between Selected Events (in Step 2) and Probabilistic Energy Assessment (in Step 3)

Weather Event

Renewables, Demand, LDC consumption

LNG, oil, fuel price, imports, outage draws - Case 1

...

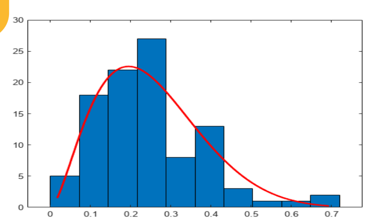
LNG, oil, fuel price, imports, outage draws - Case N

21-day assessment

21-day energy assessment result 1

...

21-day energy assessment result N



- For each selected event, ISO performed a 21-day Energy Assessment on all cases, representing LNG, oil, fuel price, import, and outage uncertainties

- ISO performed analysis of 21-day Energy Assessment outcomes

2027 STUDY YEAR RESULTS

Resource and Demand Assumptions for Study Year 2027

- 2027 baseline studies include resources that obtained a Capacity Supply Obligation (CSO) in FCA 16, resources that delisted in FCA 16 and didn't obtain a CSO and state-sponsored resources under contract or have been selected under recent RFP's
- Key changes from today's generation fleet include (all values are nameplate capacity):
  - Addition of ~600 MW of utility-scale PV
  - ~1,400 MW of battery storage
  - ~1,600 MW of offshore wind
  - Retirements totaling ~2,100 MW (including Mystic 8 and 9)
- Demand forecasts incorporate ISO's 2022 heating and transportation electrification forecasts
  - Forecasts include the effects of additional BTM PV for a total of ~9,500 MW of nameplate capacity

Resource and Demand Assumptions in Study Year 2027	
CELT Load Forecast Year	2022
FCA Results	FCA 16
Retired Capacity*	2,100
Offshore Wind Capacity*	1,600
Storage Battery Capacity*	1,450
Utility-scale PV Capacity*	1,250
BTM PV Capacity*	9,500

**capacity values listed in the table above, in MW, are based on nameplate and are approximate*

Winter Weather Events Selected By Risk Screening Model For Study Year 2027

- The 2027 winter events are characterized by short and long-duration extreme cold, low winds, and low solar irradiance
- This section reviews the following 2027 winter events:
  - Winter Cluster 1 (longer-duration events)
    - Jan 22, 1961 (event with highest average system risk*)
    - Feb 2, 1979 (event with highest severity index*)
  - Winter Cluster 2 (shorter-duration events)
    - Feb 14, 2015 (event with highest average system risk)
    - Jan 14, 1982 (event with highest severity index)
  - Medoid events were also studied; results will be briefly summarized

*Average System Risk and Severity Index are metrics calculated by EPRI's Risk Screening Model; these metrics are used to rank events and aid in the selection of events for study

Summer Weather Events Selected By Risk Screening Model For Study Year 2027

- The 2027 summer events are characterized by short to long-duration heat waves, low winds, and low solar irradiance
  - Summer Cluster 1 (longer-duration events)
    - **July 5, 2010 (highest avg. system risk*)**
    - July 13, 1979 (highest severity index*)
  - Summer Cluster 2 (short to mid-duration events)
    - July 13, 1979 (highest avg. system risk)
    - July 26, 1984 (highest severity index)
  - Summer Cluster 3 (moderate temp events with very low winds and solar)
    - July 28, 2008 (highest avg. system risk and severity index)
  - Note that July 13, 1979 is listed in two different clusters; for this 21-day weather event, two distinct climate models resulted in different outcomes in terms of the characteristics of this event
  - Medoid events were also studied; results will be briefly summarized
- Results shown focus primarily on the July 5, 2010 event

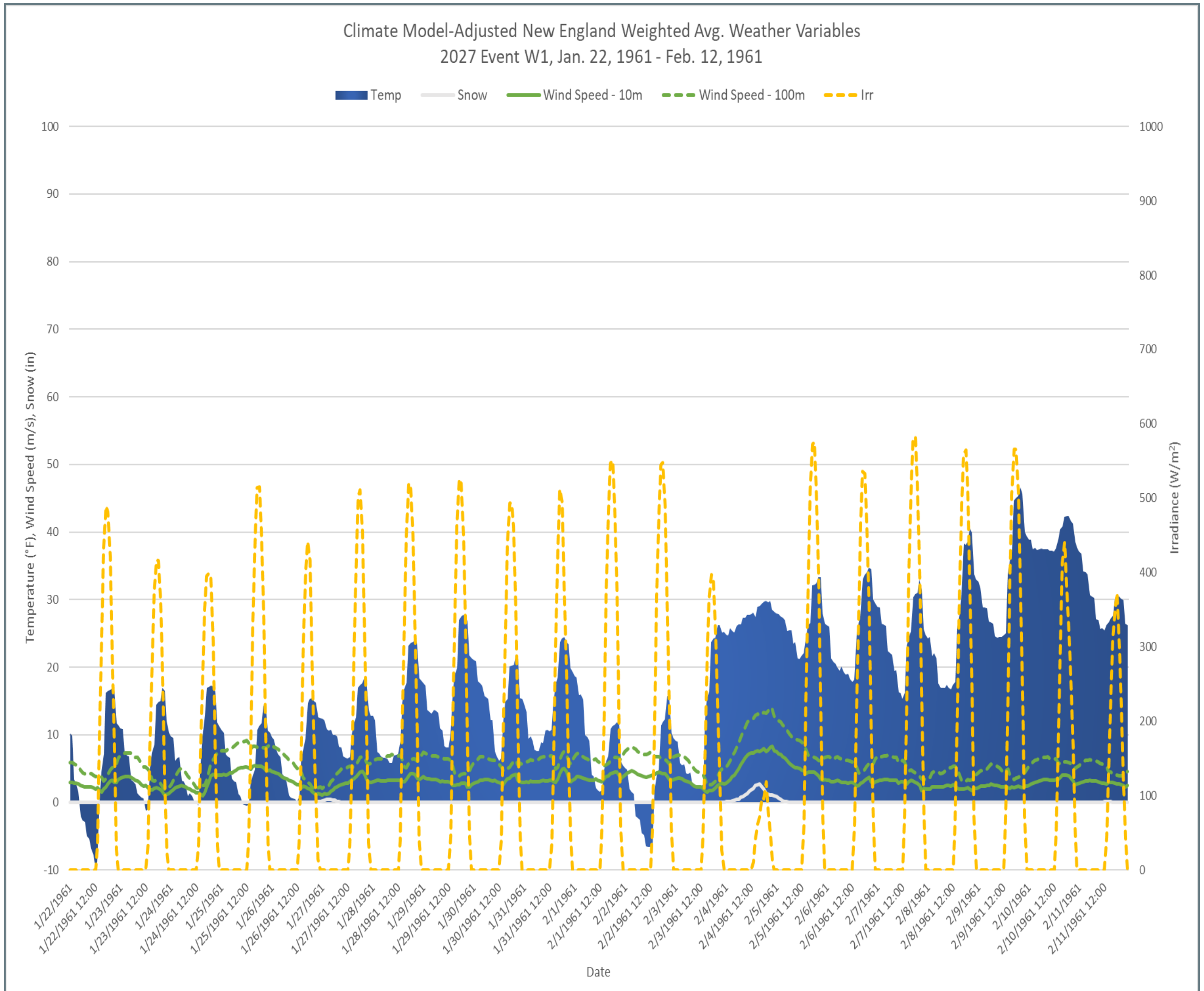
*Average System Risk, Severity Index, and medoid are metrics determined by EPRI's Risk Screening Model; these metrics are used to rank events and aid in the selection of events for study

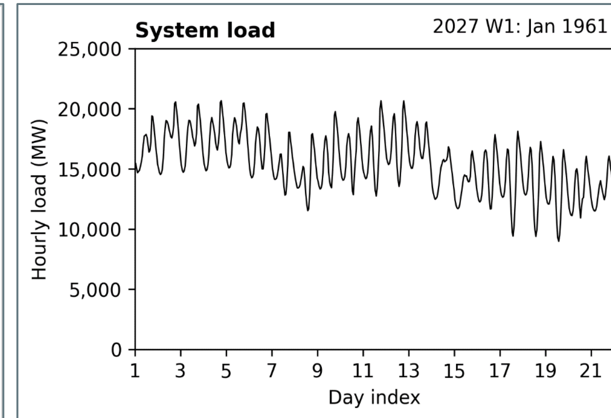
STEP 3: 2027 WINTER CLUSTER 1 (W1) RESULTS

Jan 22, 1961 (highest average system risk event) &
Feb 2, 1979 (highest severity index event)

Jan 22, 1961 Winter Event Overview

~12-Day Cold Wave Coincident With Low Wind and Very Low Solar



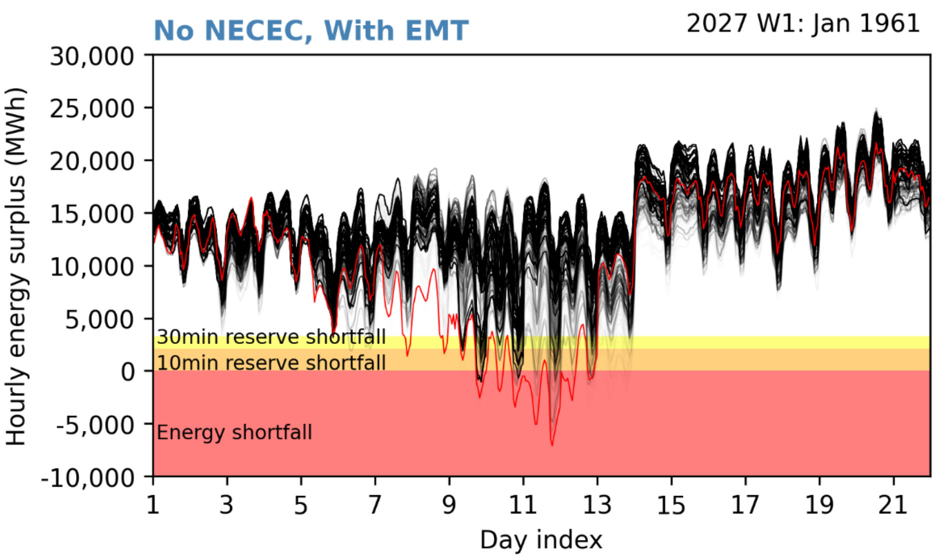


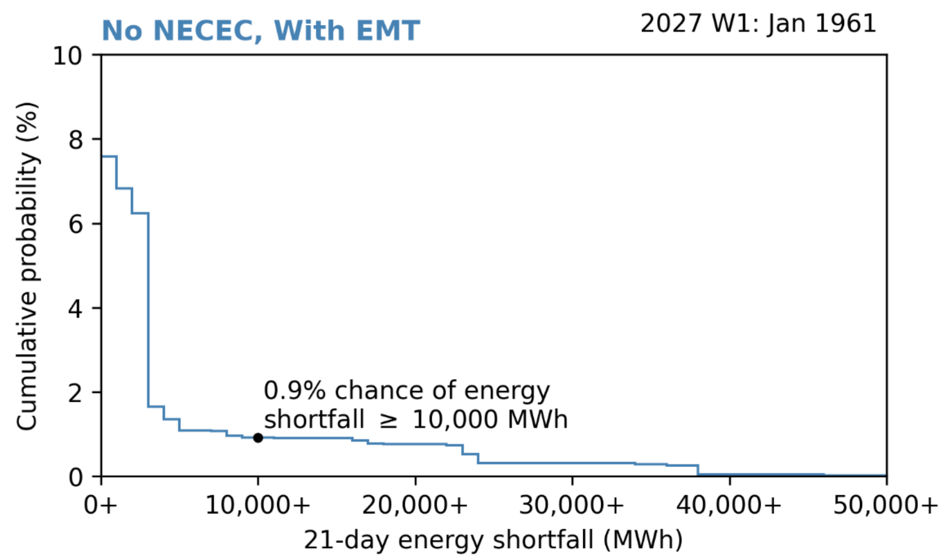
- **Min/Mean/Max (°F):** -9.8/15.8/45.7
- **Mean 100m Wind Speed (m/s):** 6.0
  - Offshore Wind avg. 800 MW/hr
  - Onshore Wind avg. 370 MW/hr
- **Mean Irradiance (W/m²):** 118.8
  - Utility Scale PV avg. 230 MW/hr
  - BTM PV avg. ~800 MW/hr
- **Avg. Energy From Renewables:** ~2,200 MW/hr
- **Peak Load:** 20,655 MW (day 4)
- **Peak Energy Demand:** ~424,000 MWh (day 5)
- **Total 21-Day Energy Demand:** 7.82 TWh
- **Historical Relevance:** Coldest 21-day period since 1950; includes two of the top 10 coldest 5-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: no NECEC, with EMT



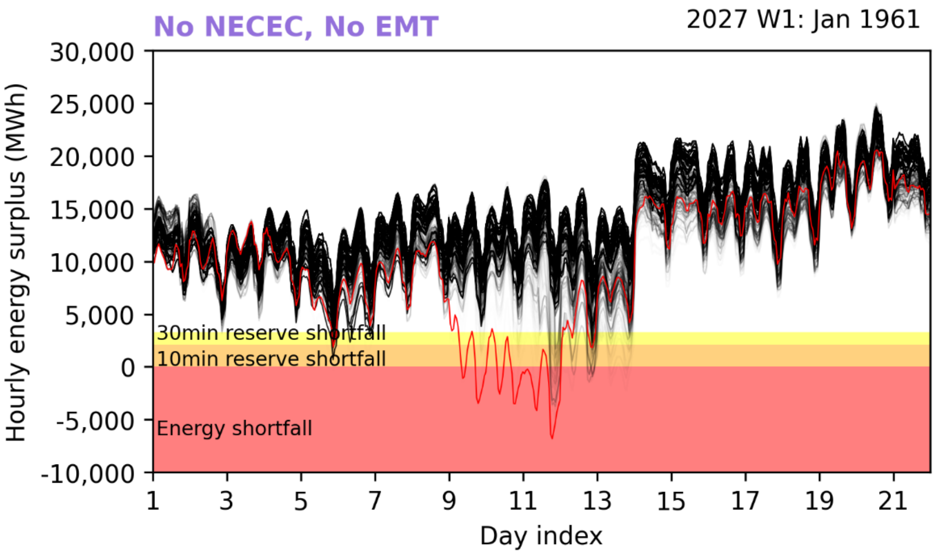


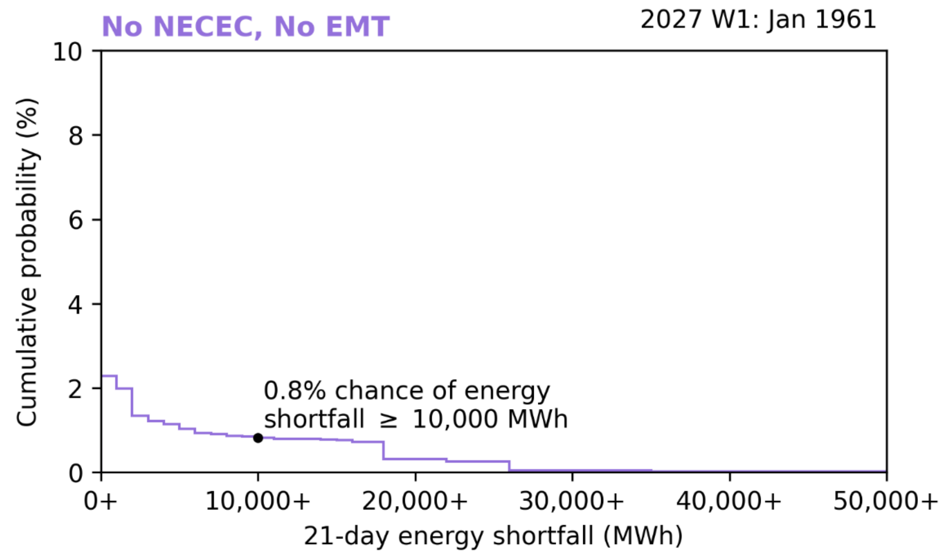
*in the energy surplus chart above (upper-left), the red highlighted trace represents the case that has the highest energy shortfall amount (MWhs); otherwise, the lower the probability of a case, the lighter its corresponding trace

# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
233	111,353	36	421	7.60%	0.0006%

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: no NECEC, no EMT

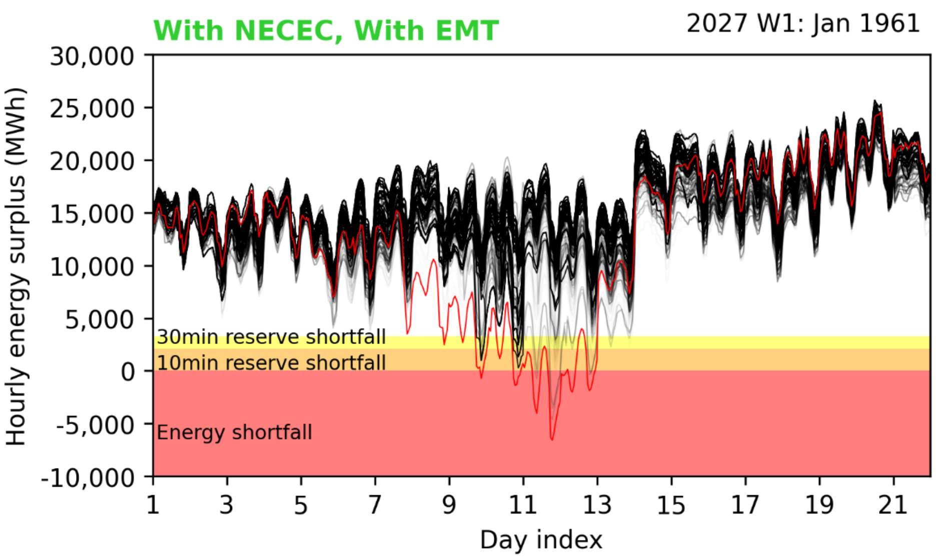


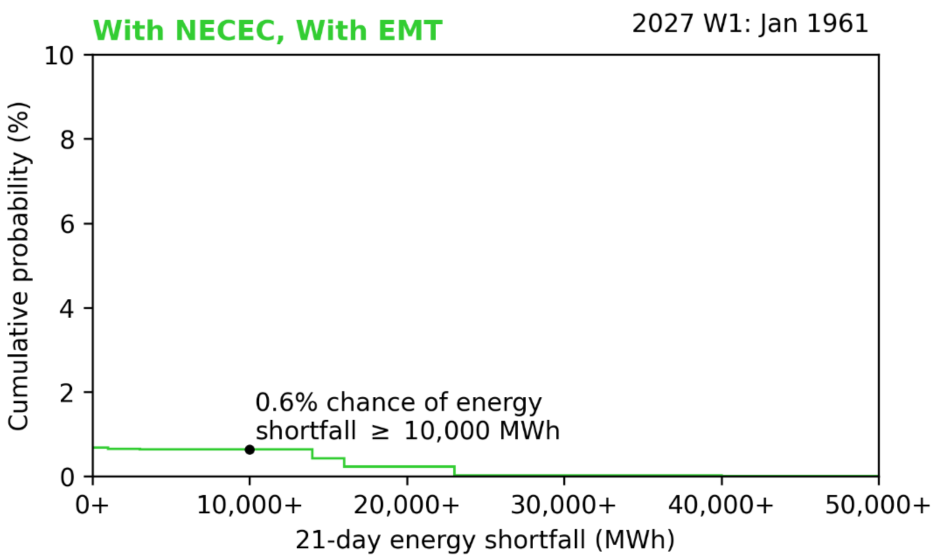


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
172	95,888	1	202	2.30%	0.0006%

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: with NECEC, with EMT

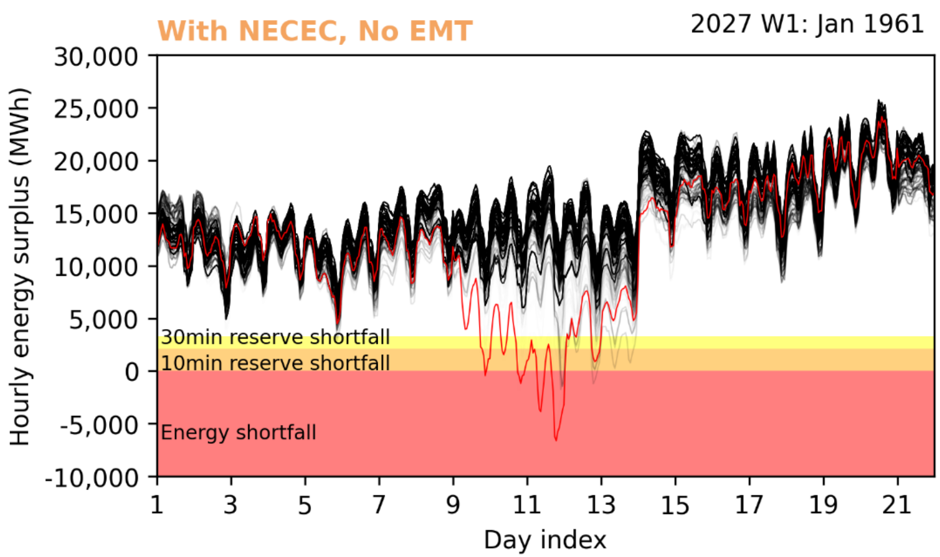


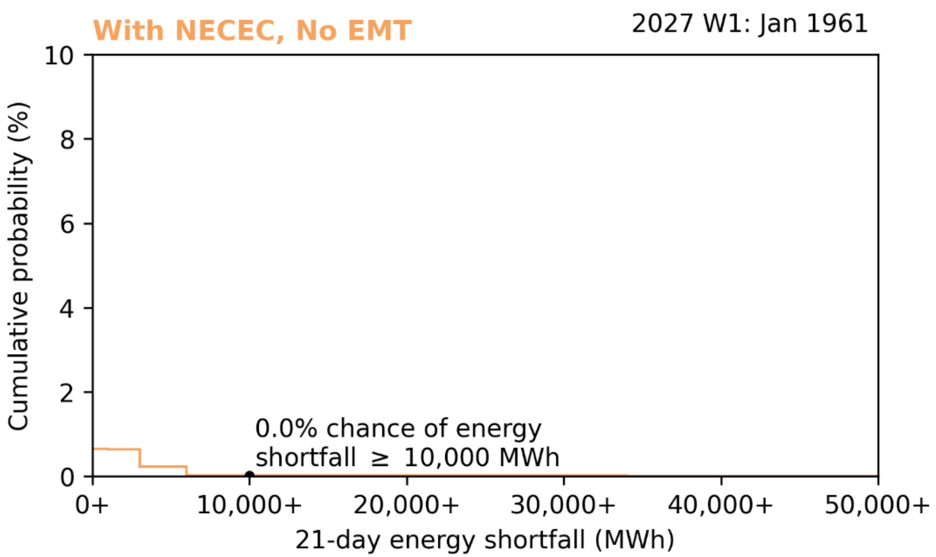


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
30	68,932	1	113	0.67%	0.004%

Summary of 21-Day Energy Analysis Results

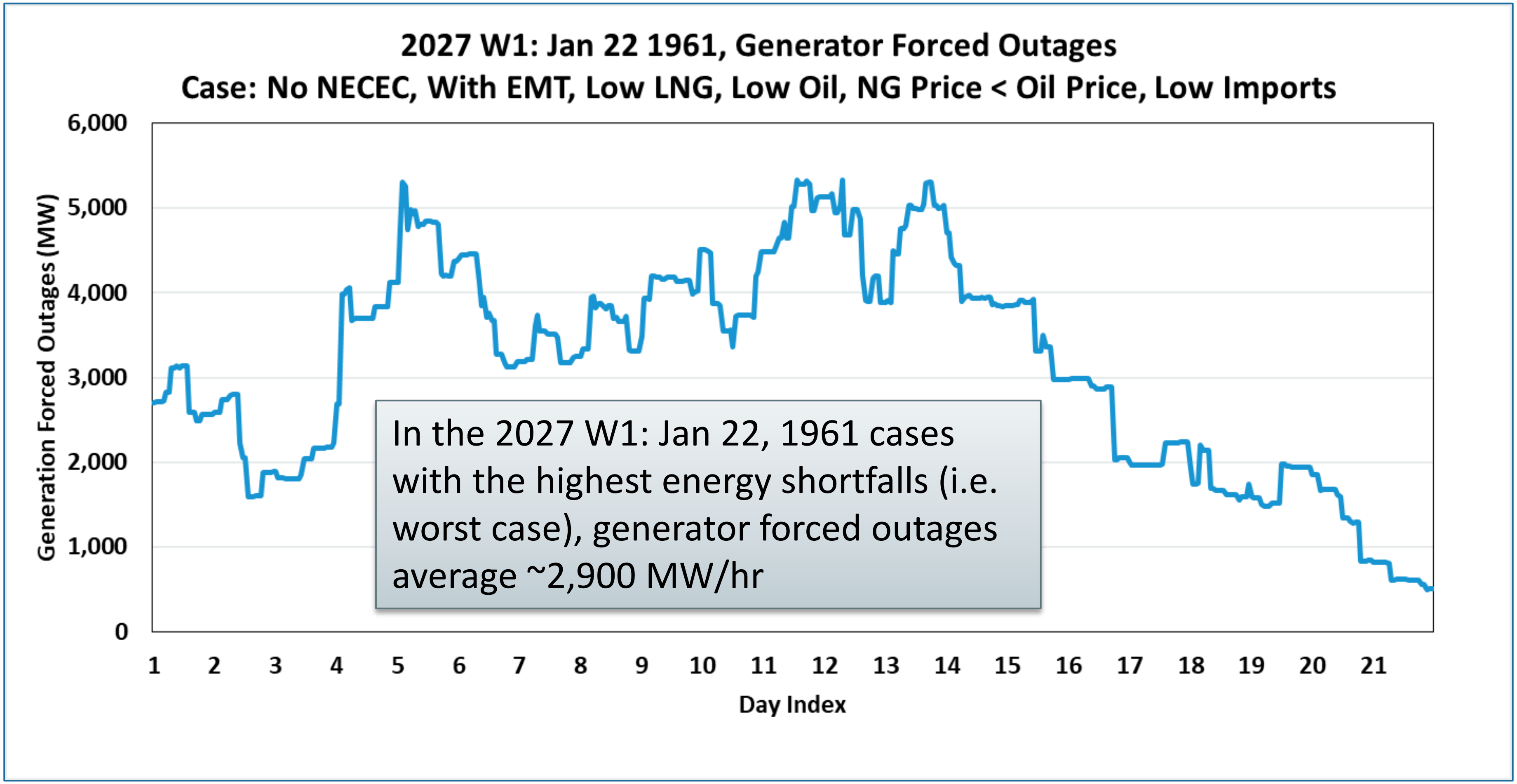
Jan 22, 1961 Event; Scenario: with NECEC, no EMT





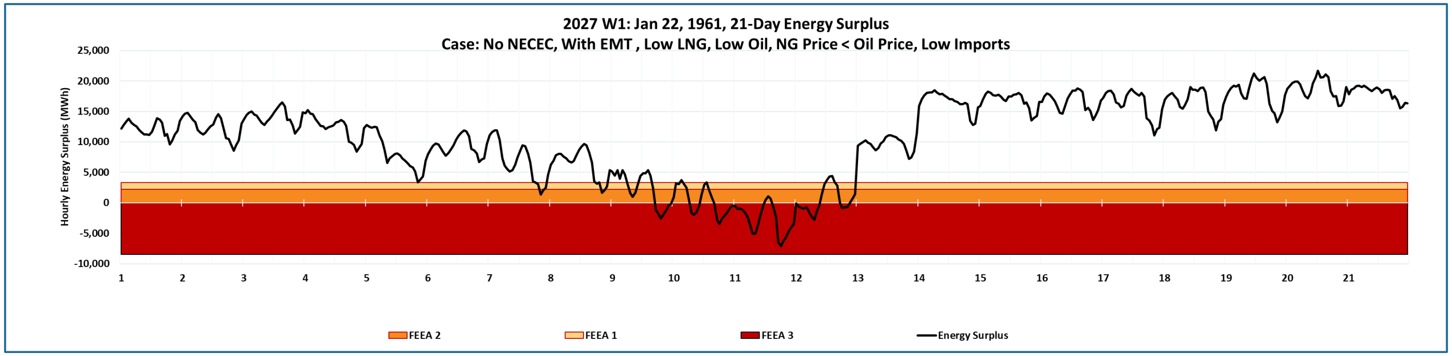
# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
25	53,518	143	28	0.64%	0.0044%

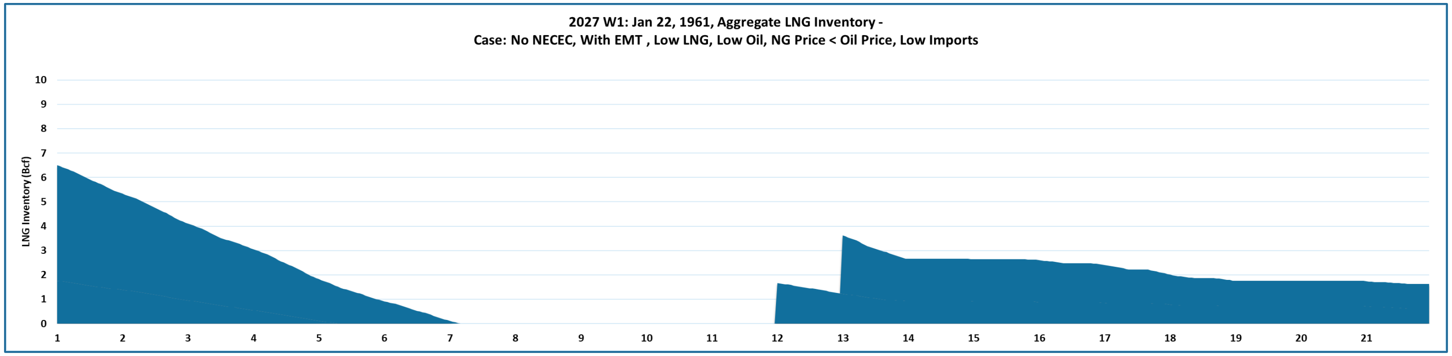
In Worst-Case Energy Shortfalls, Generator Forced Outages Range From ~500 MW/hr to ~5,400 MW/hr

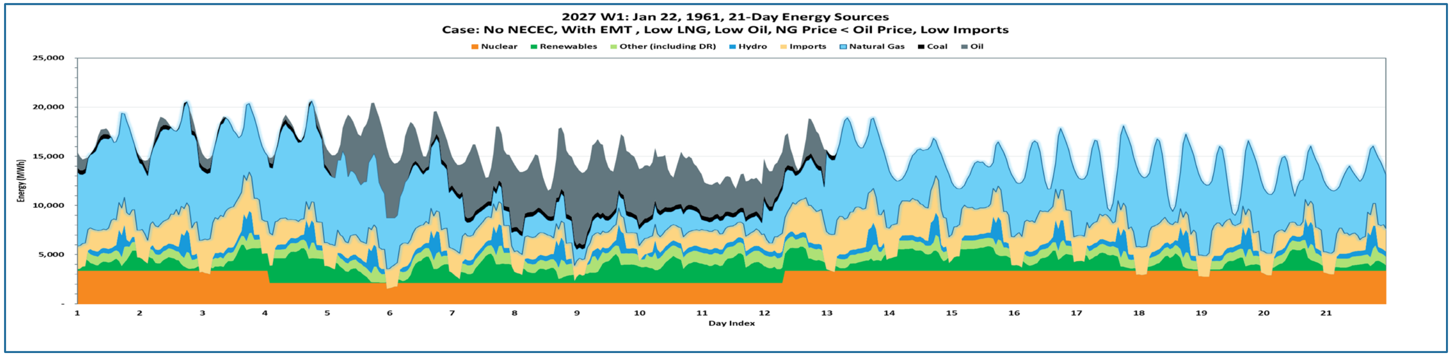


Worst-Case Energy Shortfall

Jan 22, 1961 Event; Scenario: no NECEC, with EMT; Case: Low LNG, Low Oil, NG Price < Oil Price, Low Imports

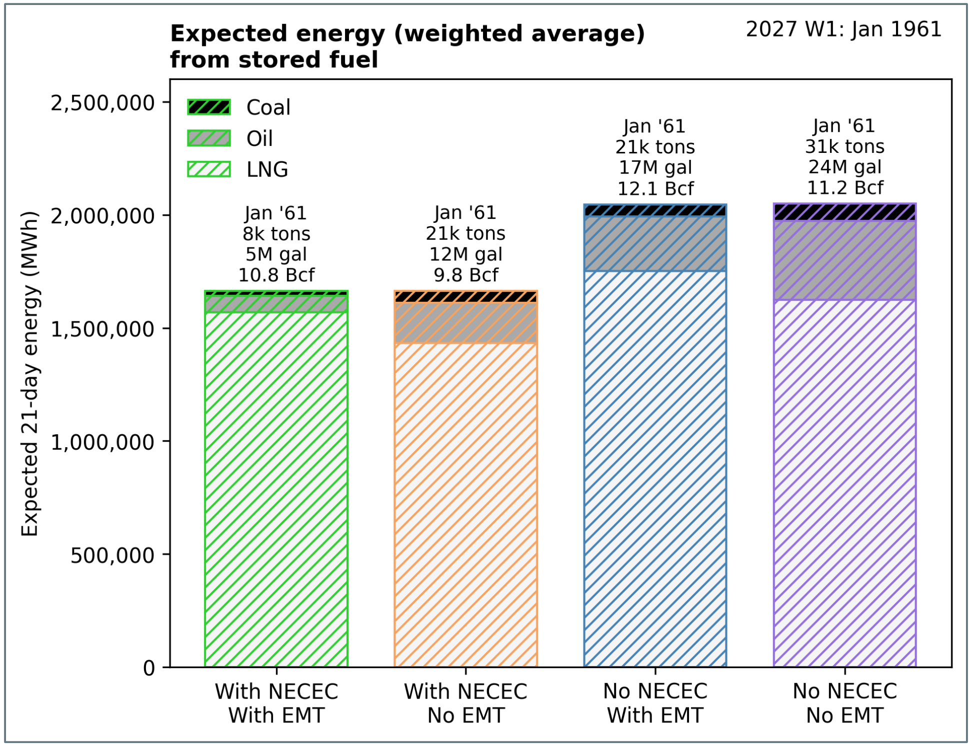




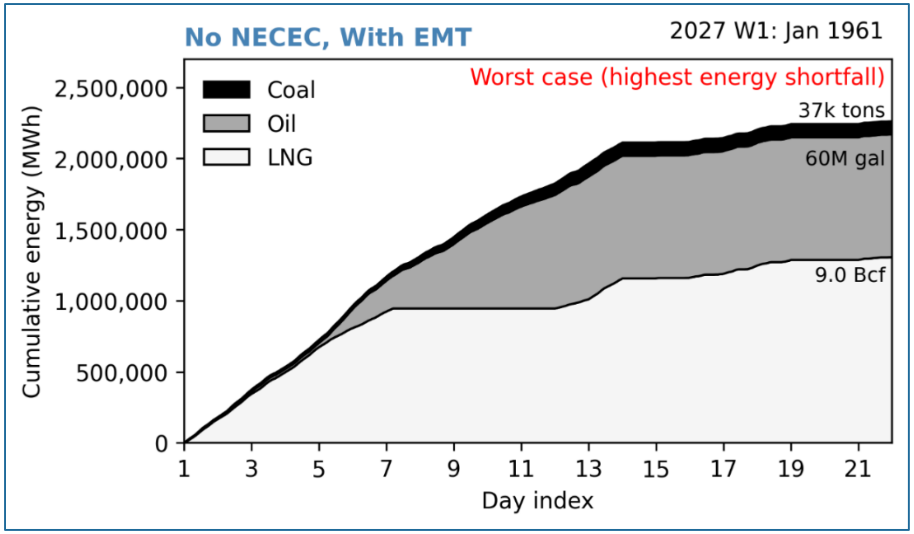


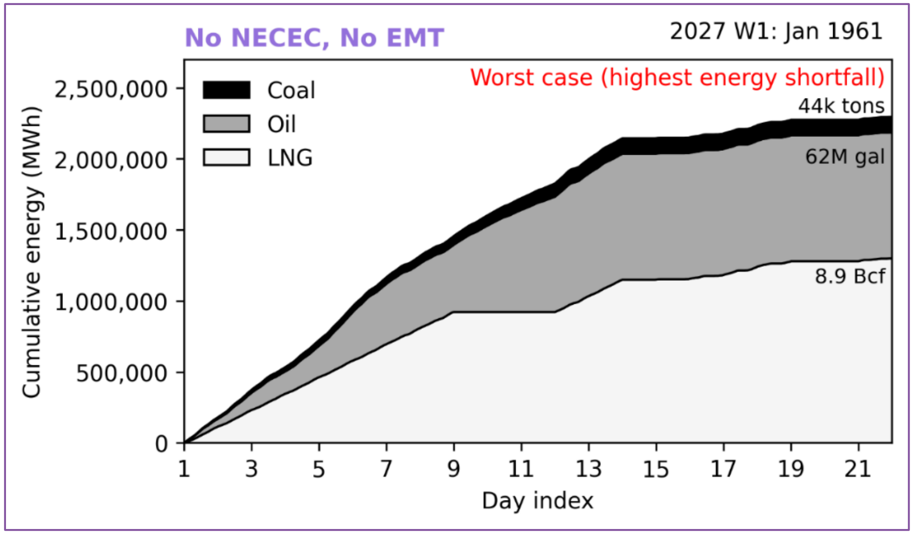
Energy Shortfall – FEEA3 (MWh)	111,353
10-Min Reserve Shortfall – FEEA2 (MWh)	135,892
30-Min Reserve Shortfall – FEEA1 (MWh)	87,332
Starting Inventory – LNG (Bcf)	6.5
LNG Replenishment (Bcf), on days 12 & 13	4.1
LNG Usage (Bcf)	9.0
Fuel Oil Starting Inventory (gal)	~96.5 M
Fuel Oil Replenishment (gal), as needed	~39.0 M
Fuel Oil Usage (gal)	~60.4 M

In Worst Case Energy Shortfalls, Increases in Stored Fuel Usage Are Notable



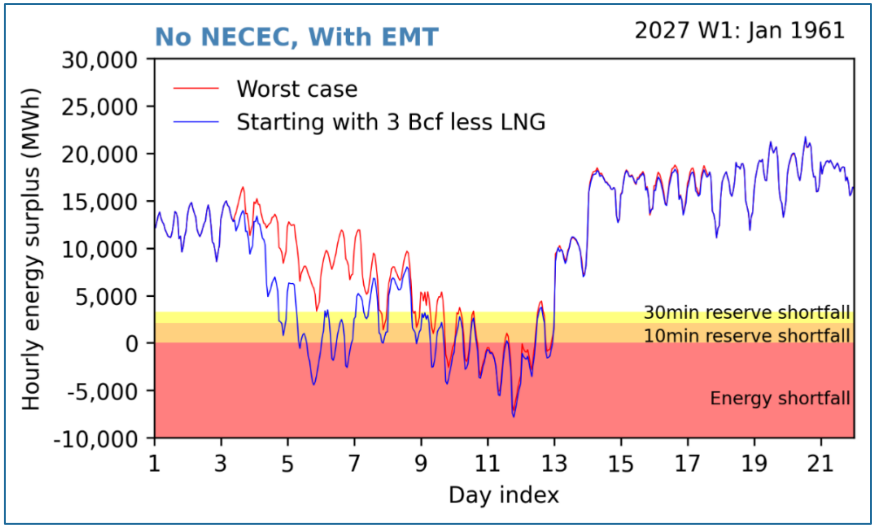
In the figure above, the expected energy from stored fuel is the weighted avg. quantity of stored fuels used across all cases in a given scenario and the figures to the right are for the worst case



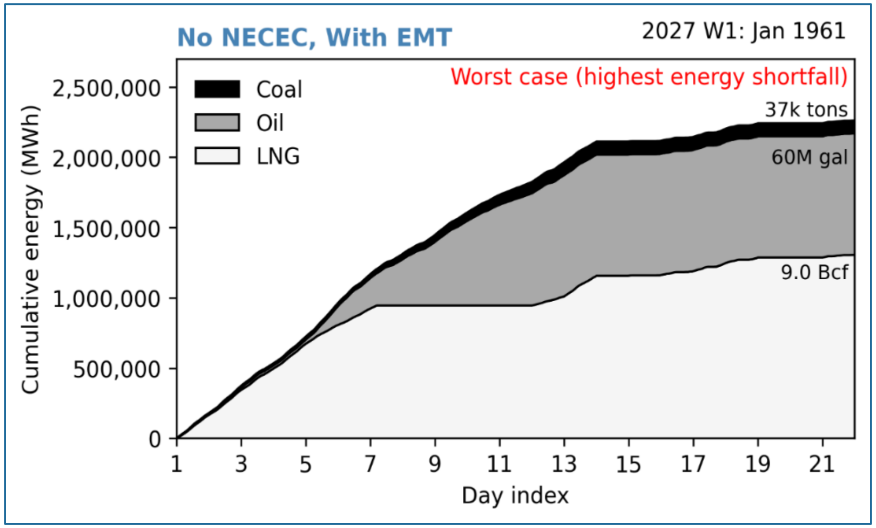


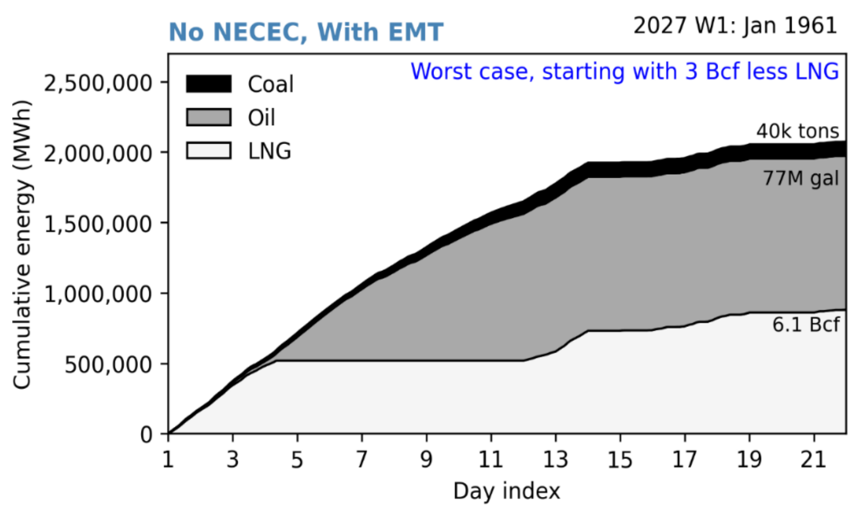
Sensitivity to Starting LNG inventory

Jan 22, 1961 Event; Scenario: no NECEC, with EMT; Case: Low LNG, Low Oil, NG Price < Oil Price, Low Imports



- To illustrate the sensitivity of total energy shortfall to LNG inventories, ISO studied a sensitivity case* with a 3 Bcf lower starting LNG inventory
  - In this sensitivity case, the starting LNG inventory of ~6.5 Bcf is reduced to ~3.5 Bcf
  - Similar to the un-adjusted case, LNG replenishment of ~2.4 Bcf and ~1.7 Bcf occurs on days 12 and 13, respectively
- Worst case energy shortfall increases to ~200K MWh (~80%); results were similar in a sensitivity case run on the No NECEC, No EMT scenario





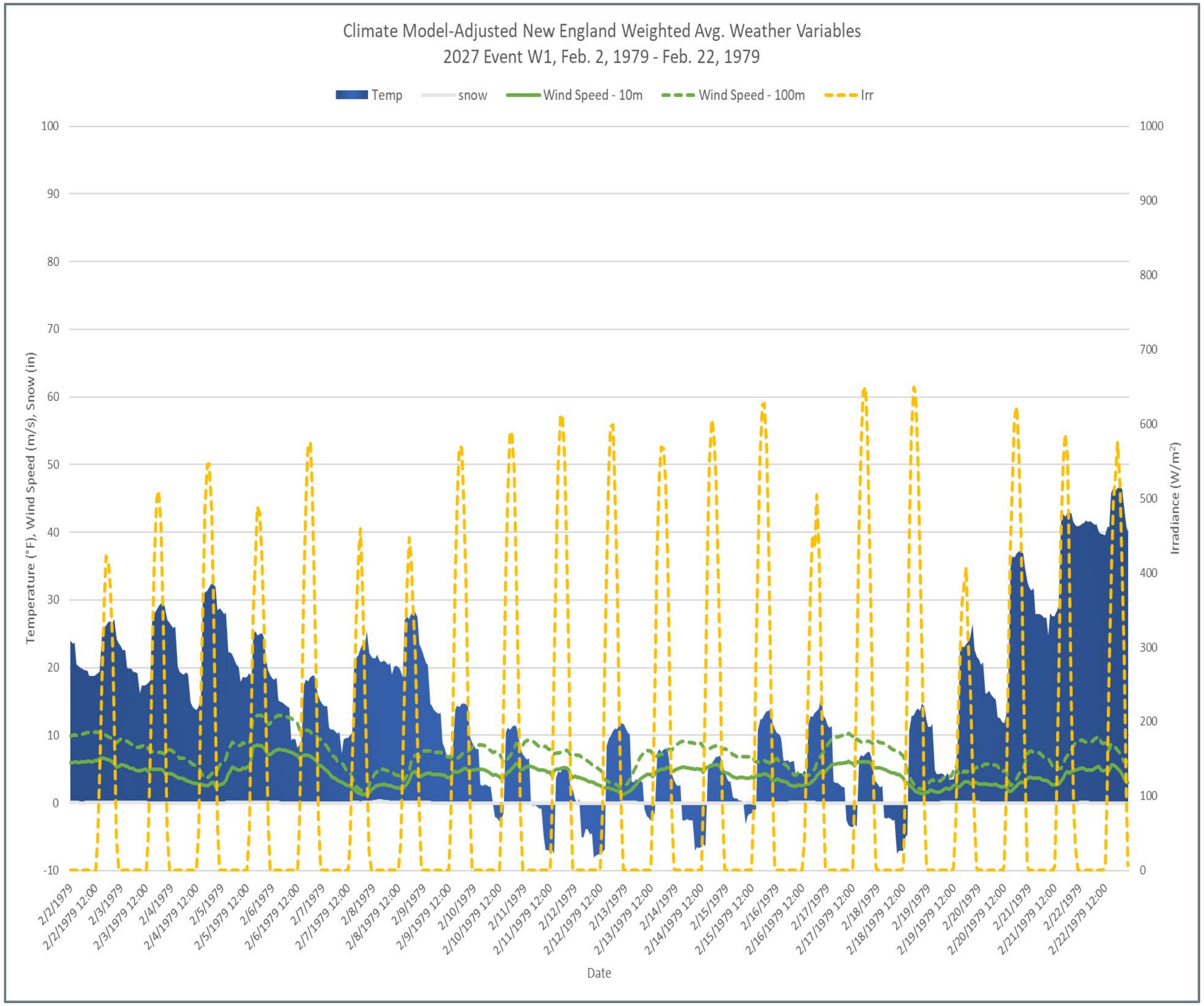
*no probability is associated with this sensitivity case

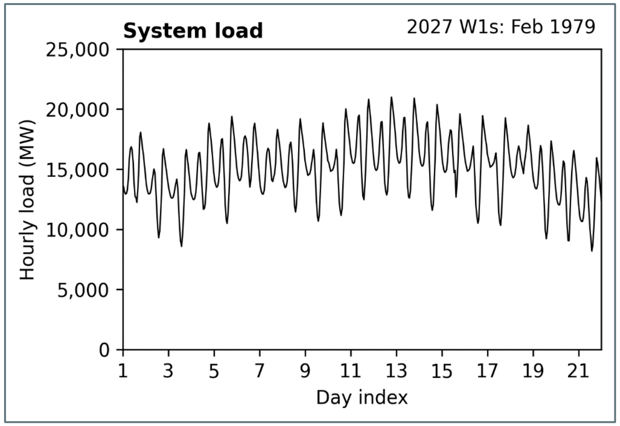
Scenario Modeling of the Everett Marine Terminal

- Scenarios without EMT assume that its capacity to provide energy to the system is picked up by the remaining LNG facilities and the capacity of fuel-oil burning resources
- The primary difference between with EMT and without EMT scenarios is the maximum daily LNG injection **rate** (0.8 Bcf/d without EMT, 1.2 Bcf/d with EMT)
- Regional aggregate LNG inventories are similar in with EMT and without EMT scenarios; ISO has not attempted to quantify the extent to which regional LNG inventories might vary based on EMT's operational status
  - The LNG model for this study is based upon the seasonal (Dec-Mar) LNG demand profiles developed by Consultants
- Results of with and without EMT scenarios are highly dependent on the unique characteristics of a given event, including the timing of the highest energy demands, starting LNG inventories, and timing of LNG replenishment
  - Higher rates of LNG injection (i.e., LNG injection rates in scenarios with EMT) may deplete LNG inventories quicker prior to replenishment, leading to larger energy shortfalls in some cases with EMT than in similar cases without EMT

Feb 2, 1979 Winter Event Overview

~10-Day Cold Wave Coincident With Low Winds and Low Solar



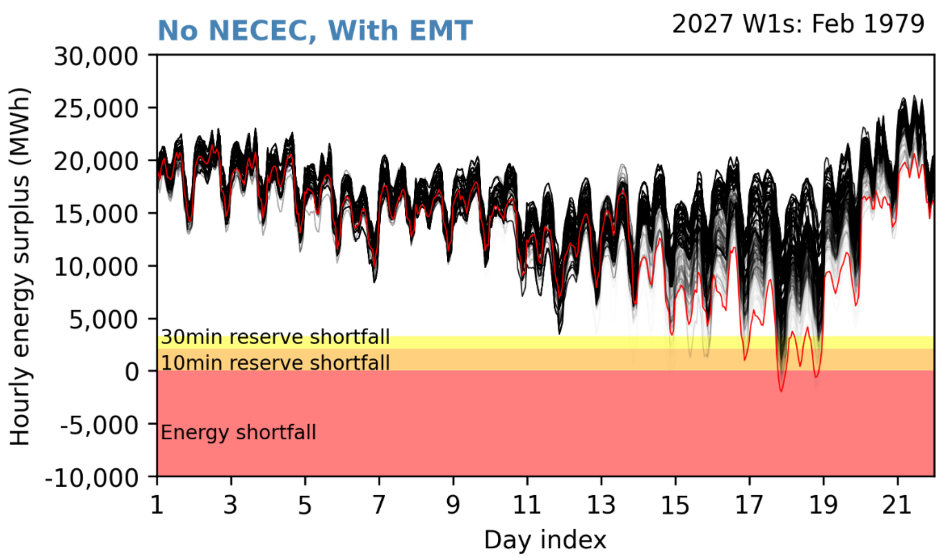


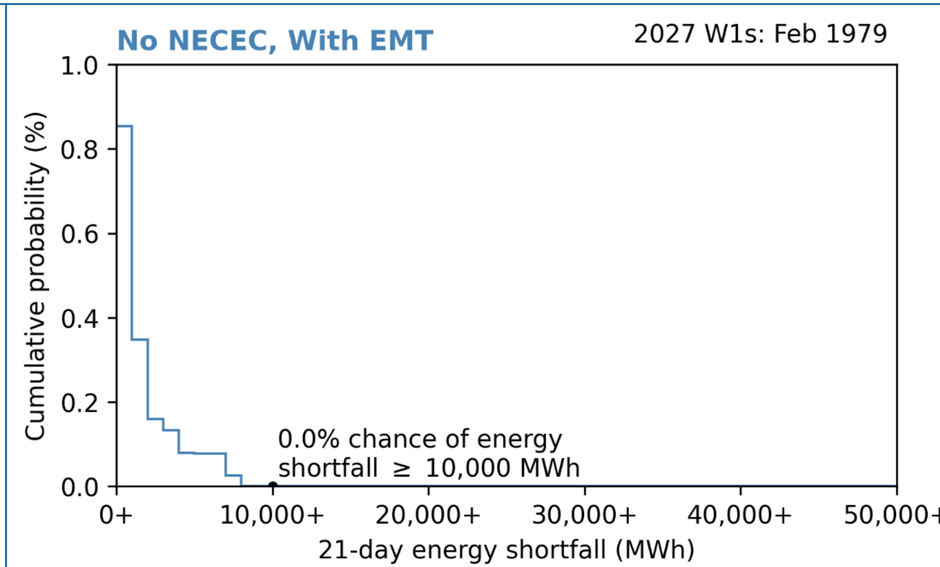
- **Min/Mean/Max (°F):** -8.1/14.3/46.6
- **Mean 100m Wind Speed (m/s):** 7.1
  - Offshore Wind avg. 1,120MW/hr
  - Onshore Wind avg. 580 MW/hr
- **Mean Irradiance (W/m²):** 142.0
  - Utility Scale PV avg. 280 MW/hr
  - BTM PV avg. ~1,400 MW/hr
- **Avg. Energy From Renewables:** ~3,380 MW/hr
- **Peak Load:** 20,994 MW (day 11)
- **Peak Energy Demand:** ~403,000 MWh (day 12)
- **Total 21-Day Energy Demand:** 7.59 TWh
- **Historical Relevance:** The actual weather during this stretch included the coldest 5-day and 10-day period since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Feb 2, 1979 Event; Scenario: no NECEC, with EMT

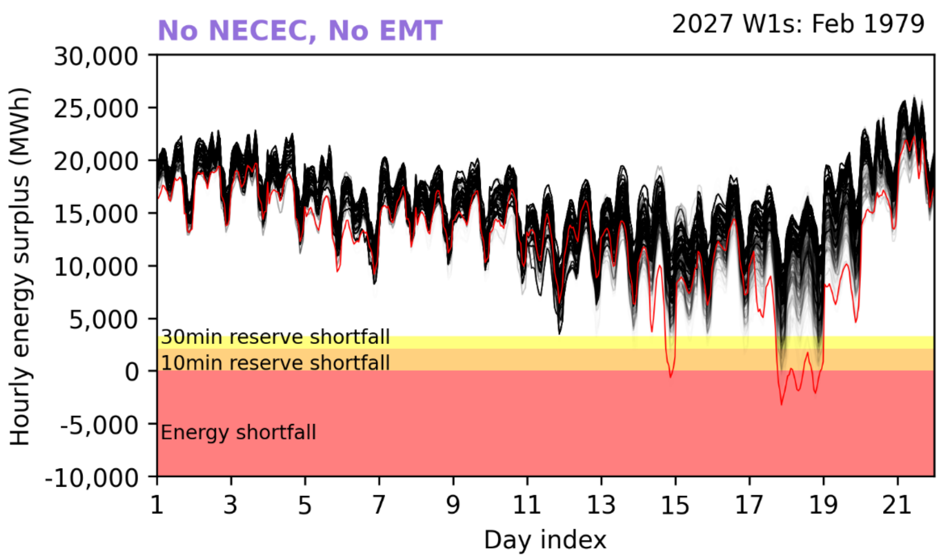


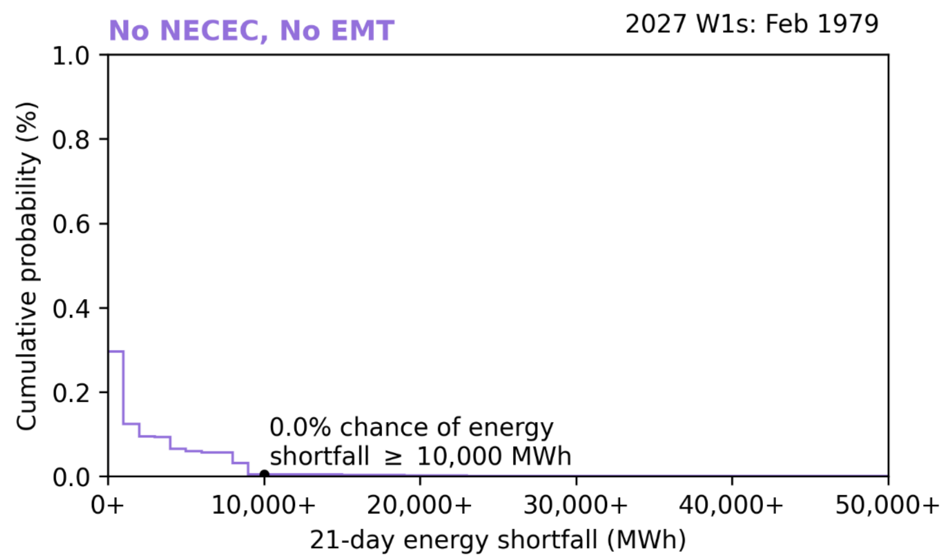


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
48	7,545	74	13	0.85%	0.026%

Summary of 21-Day Energy Analysis Results

Feb 2, 1979 Event; Scenario: no NECEC, no EMT

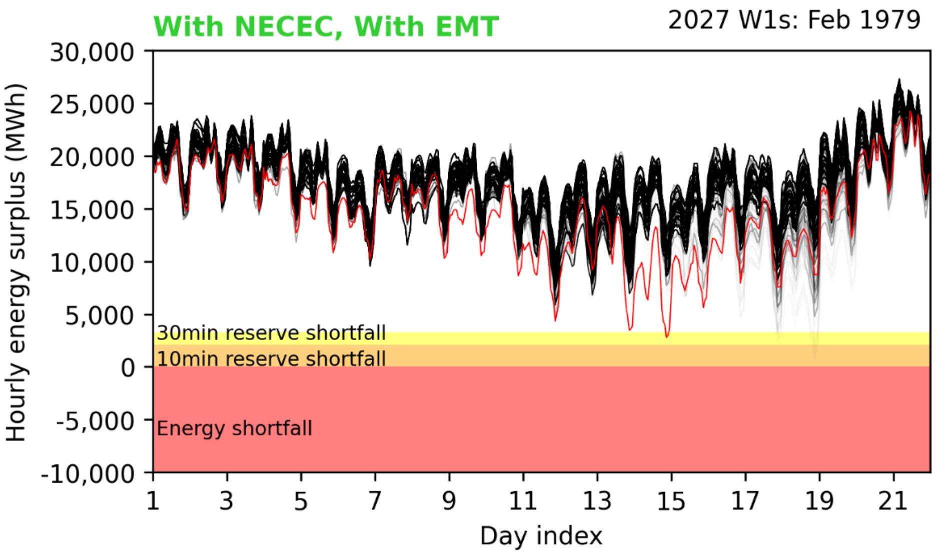


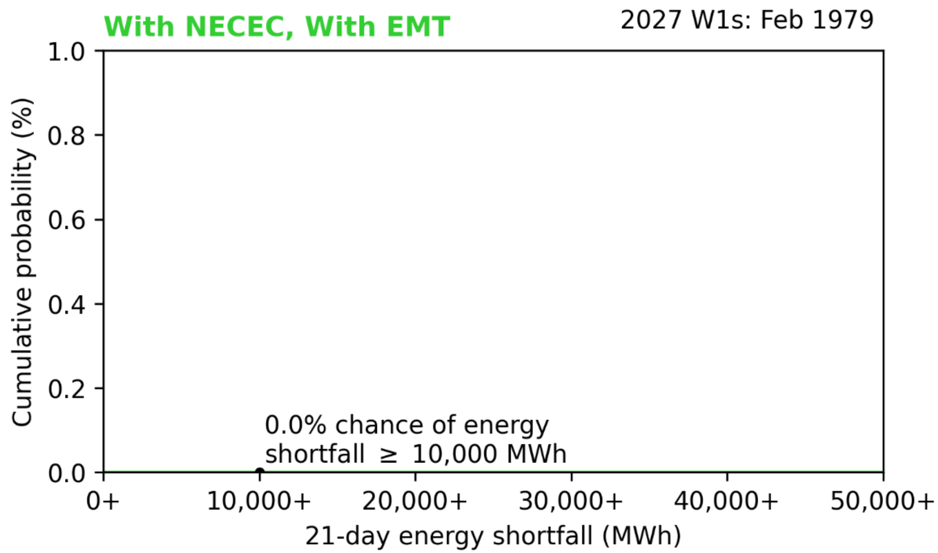


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
67	28,348	18	7	0.30%	0.0006%

Summary of 21-Day Energy Analysis Results

Feb 2, 1979 Event; Scenario: with NECEC, with EMT

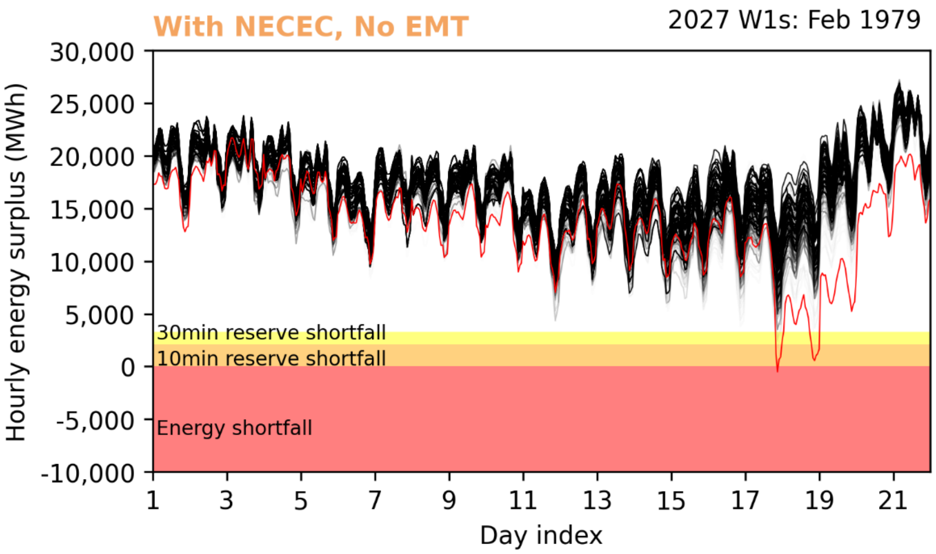


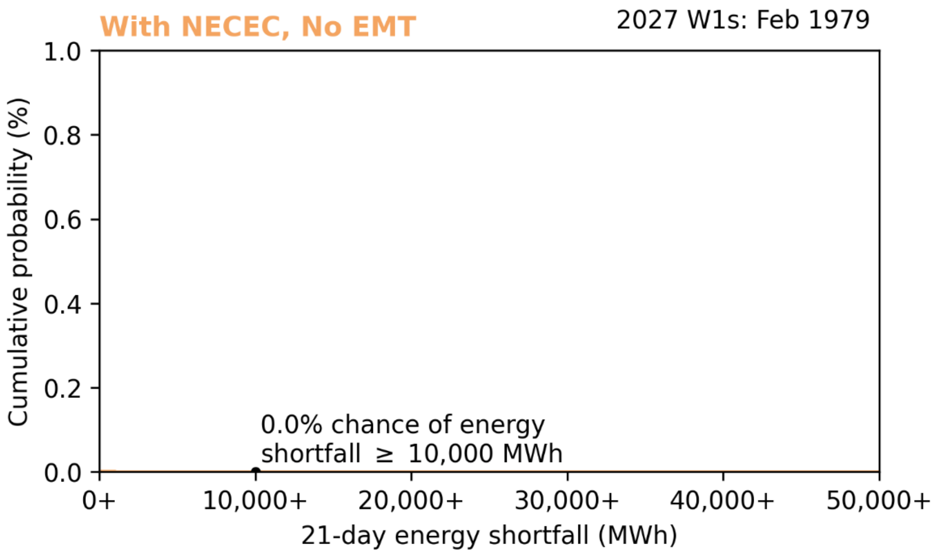


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

Summary of 21-Day Energy Analysis Results

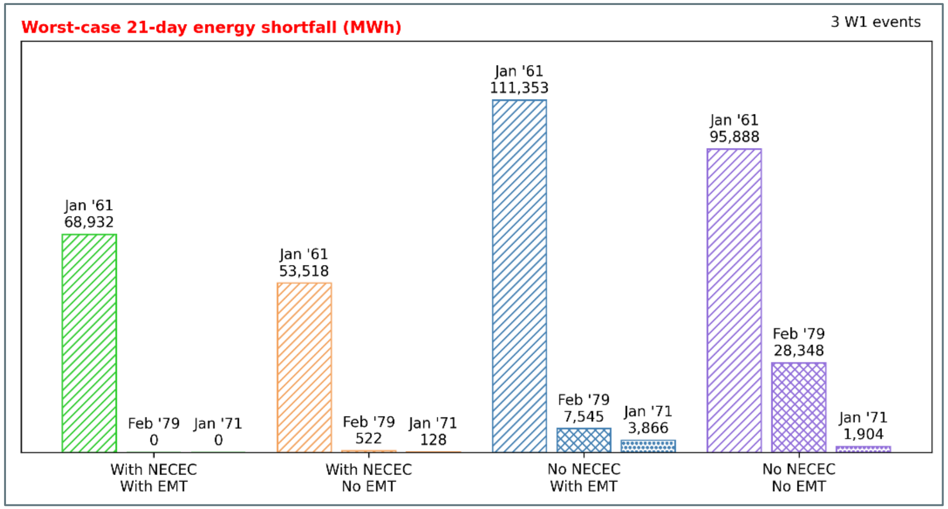
Feb 2, 1979 Event; Scenario: with NECEC, no EMT

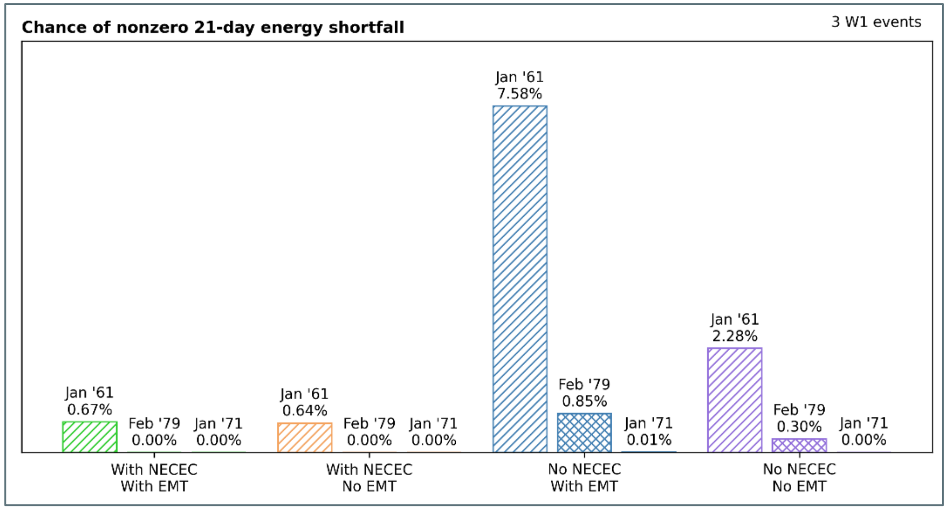




# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2	522	10	0	0.001%	0.0006%

2027 Winter Cluster 1
Energy Shortfall Quantities and Probabilities





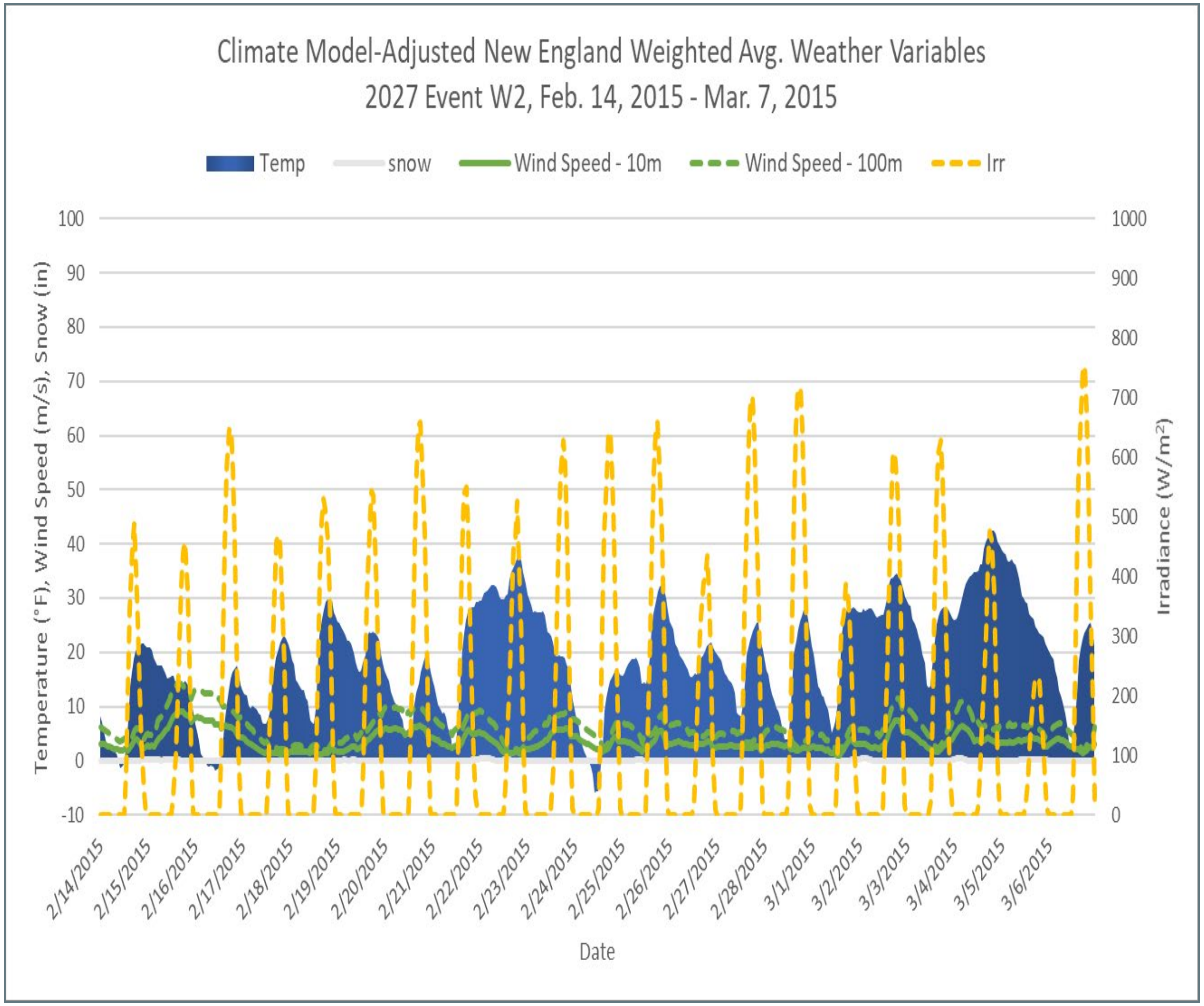
- Results of the Winter Cluster 1 medoid event (Jan 15, 1971) are included in the figures above; energy shortfall in the medoid event cases is negligible
- Results of Winter Cluster 1 studies reveal:
  - Similar energy adequacy risk with and without EMT in-service; as noted, results with and without EMT are highly dependent on the characteristics of a given event
  - Risks are mitigated by incremental imports from NECEC

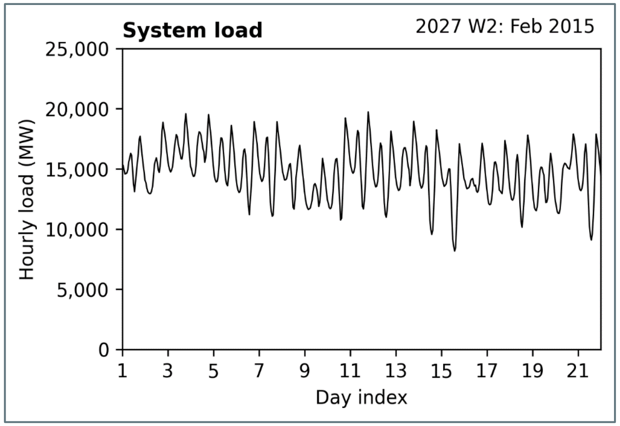
STEP 3: 2027 WINTER CLUSTER 2 (W2) RESULTS

Feb 14, 2015 (highest average system risk event) &
Jan 14, 1982 (highest severity index event)

Feb 14, 2015 Winter Event Overview

Multiple Short-Duration Cold Waves Coincident With Low Wind and Low Solar



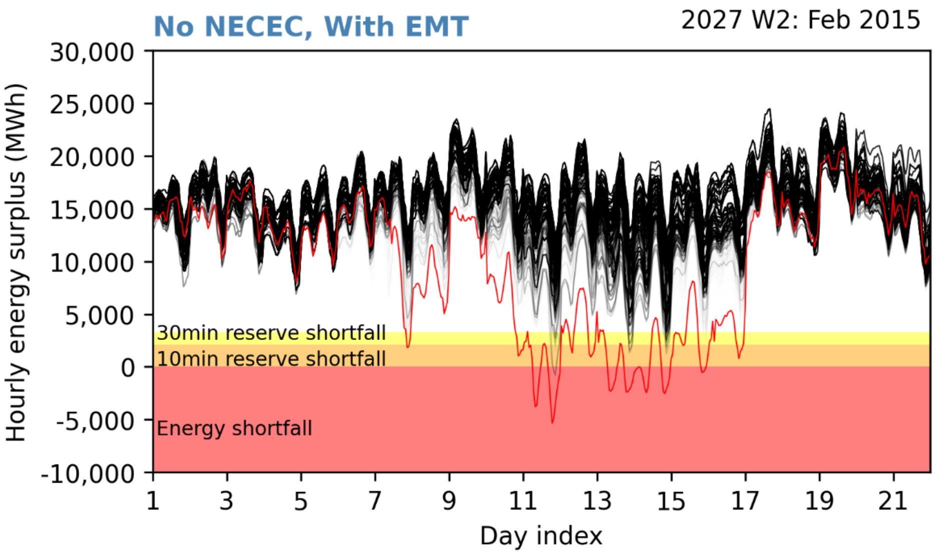


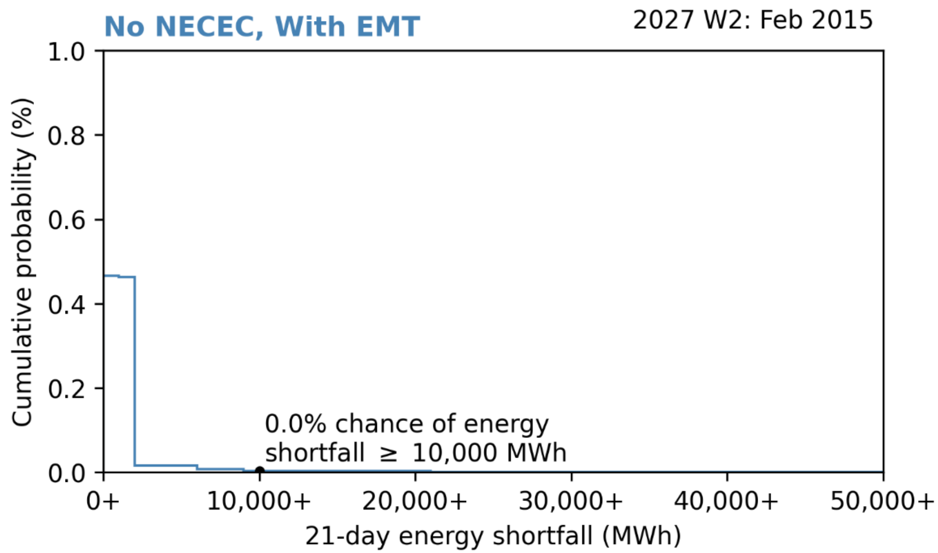
- **Min/Mean/Max (°F):** -5.8/19.0/42.5
- **Mean 100m Wind Speed (m/s):** 6.0
  - Offshore Wind avg. 740 MW/hr
  - Onshore Wind avg. 410 MW/hr
- **Mean Irradiance (W/m²):** 147.6
  - Utility Scale PV avg. 280 MW/hr
  - BTM PV avg. ~1,100 MW/hr
- **Avg. Energy From Renewables:** ~2,530 MW/hr
- **Peak Load:** 19,730 MW (day 11)
- **Peak Energy Demand:** ~399,000 MWh (day 3)
- **Total 21-Day Energy Demand:** 7.43 TWh
- **Historical Relevance:** One of Top 10 coldest 21-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: no NECEC, with EMT

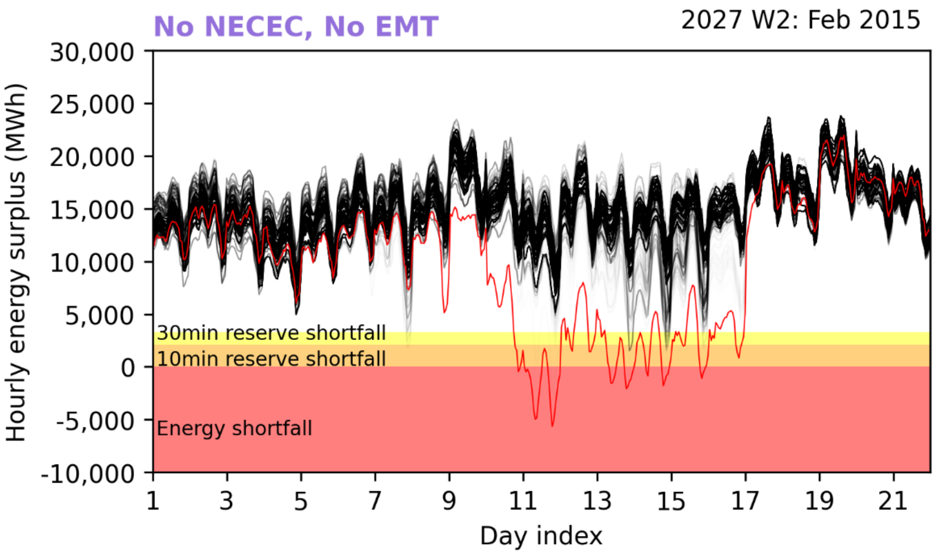


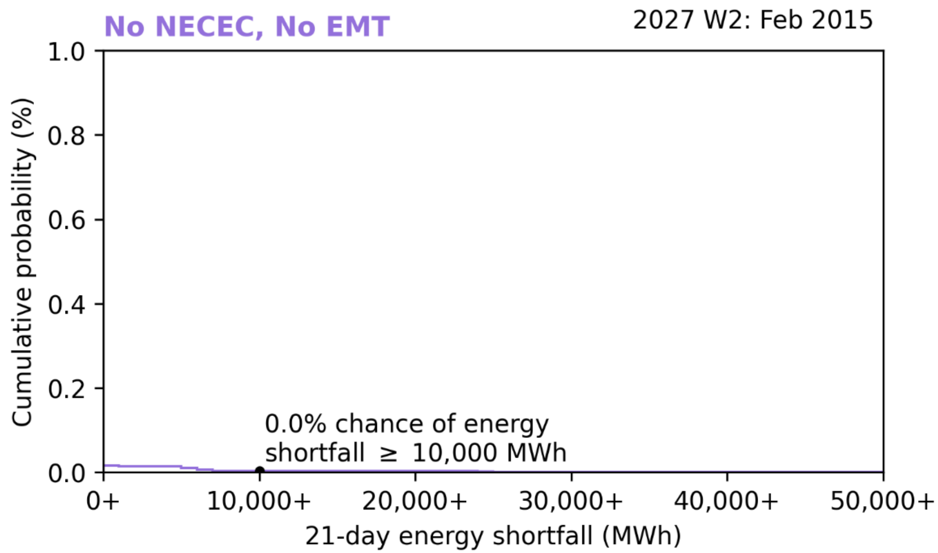


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
33	78,148	18	7	0.47%	0.000005%

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: no NECEC, no EMT

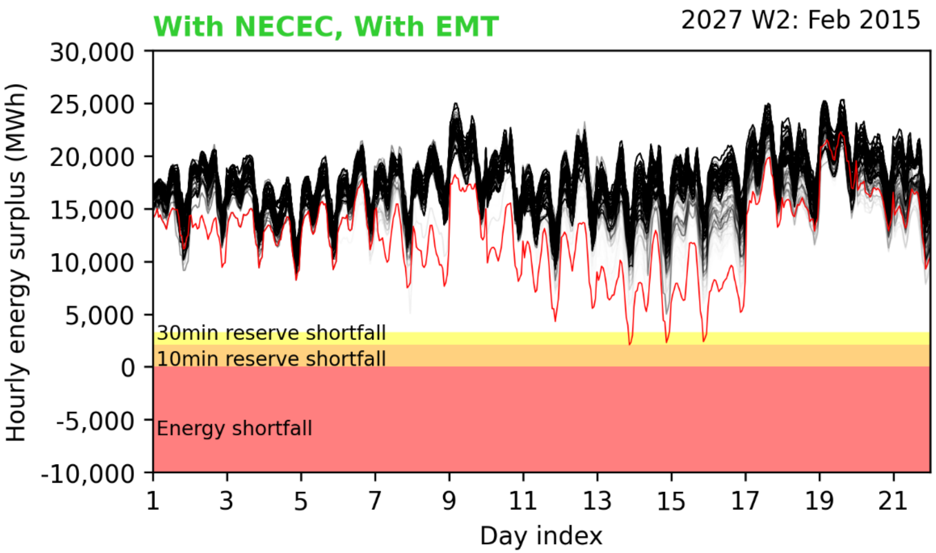


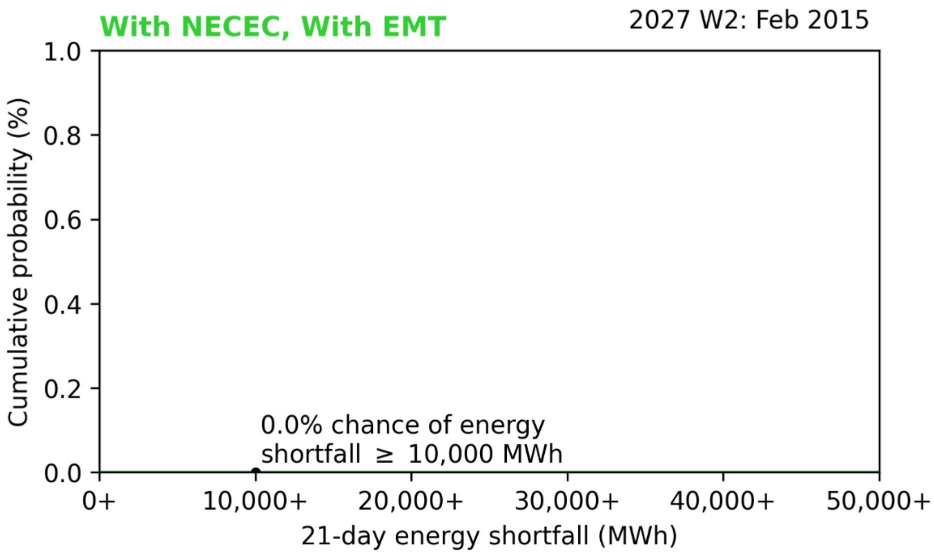


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
18	71,255	10	1	0.02%	0.000005%

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: with NECEC, with EMT

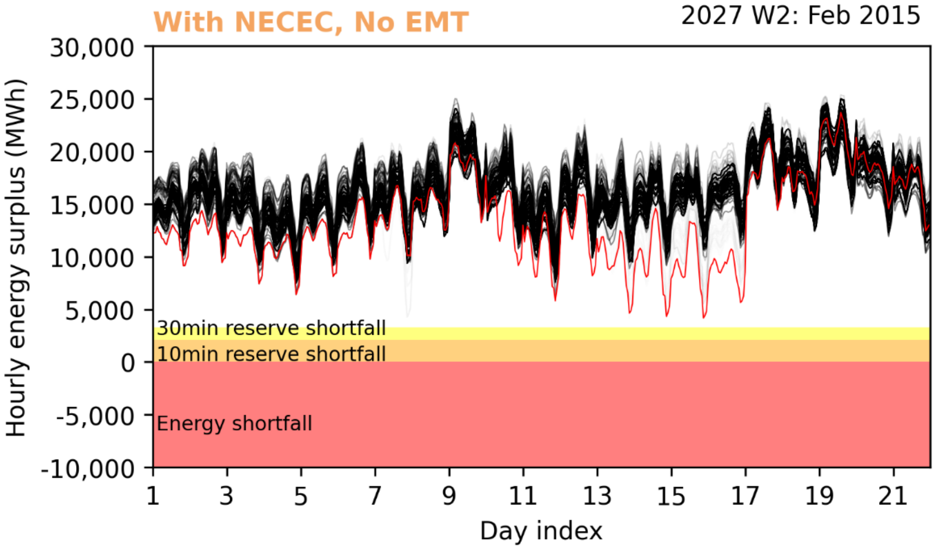


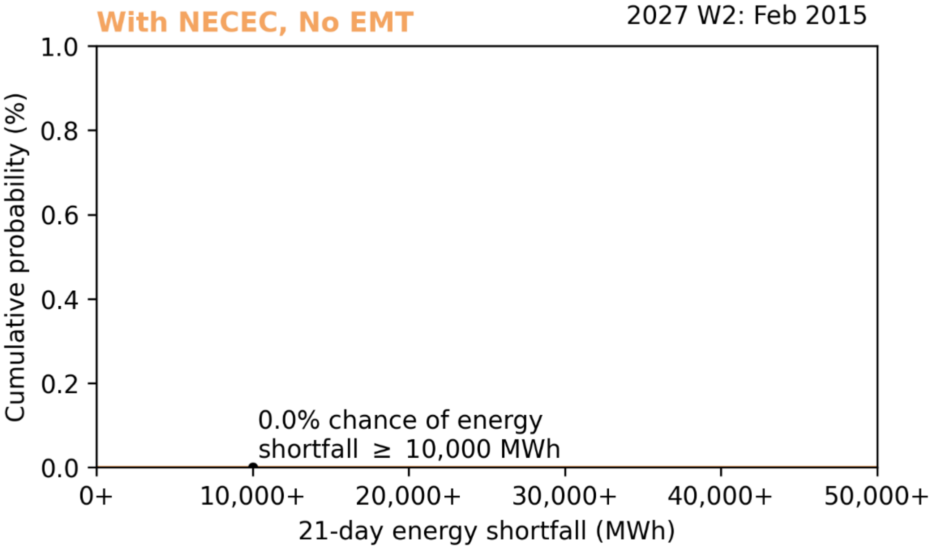


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: with NECEC, no EMT





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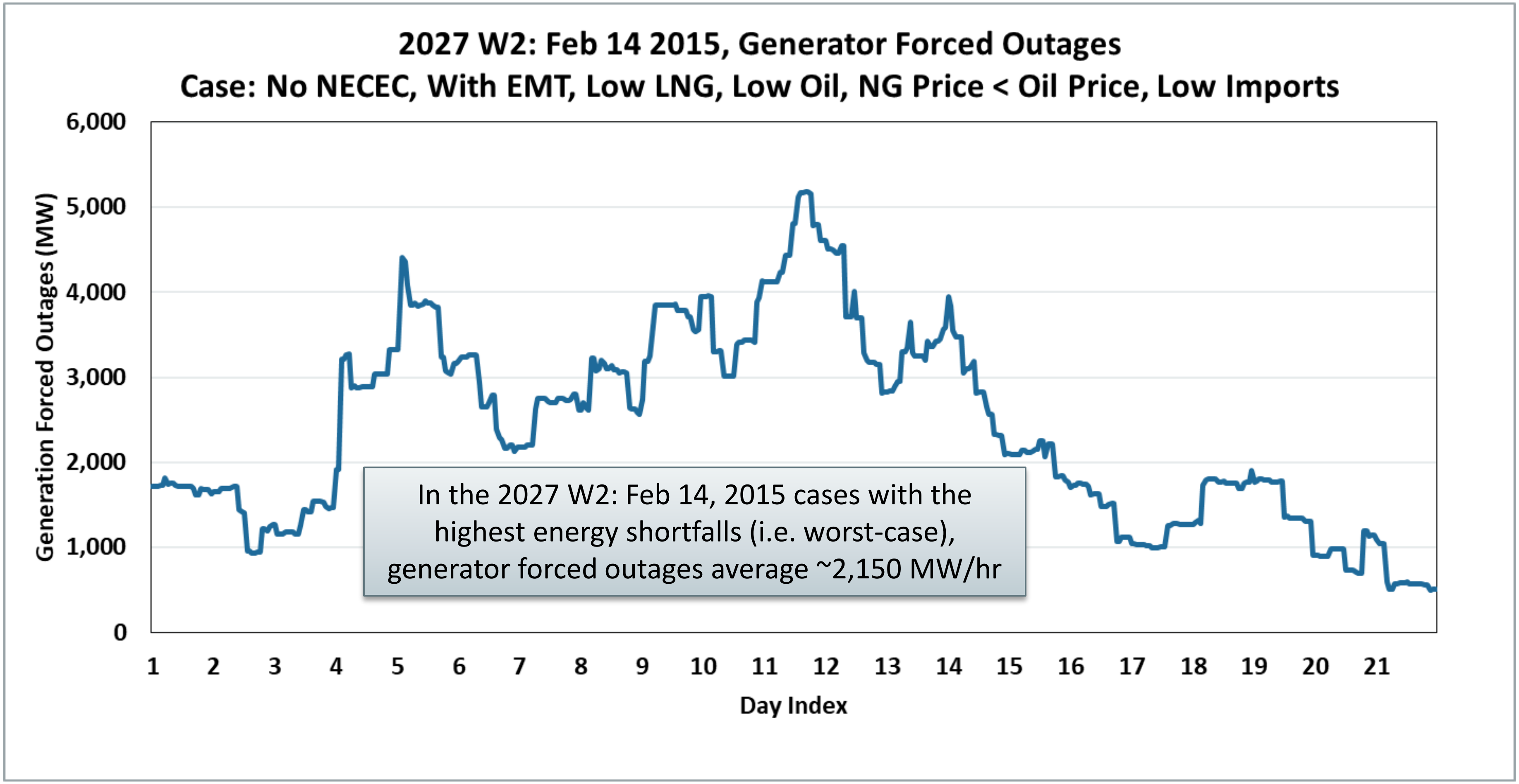
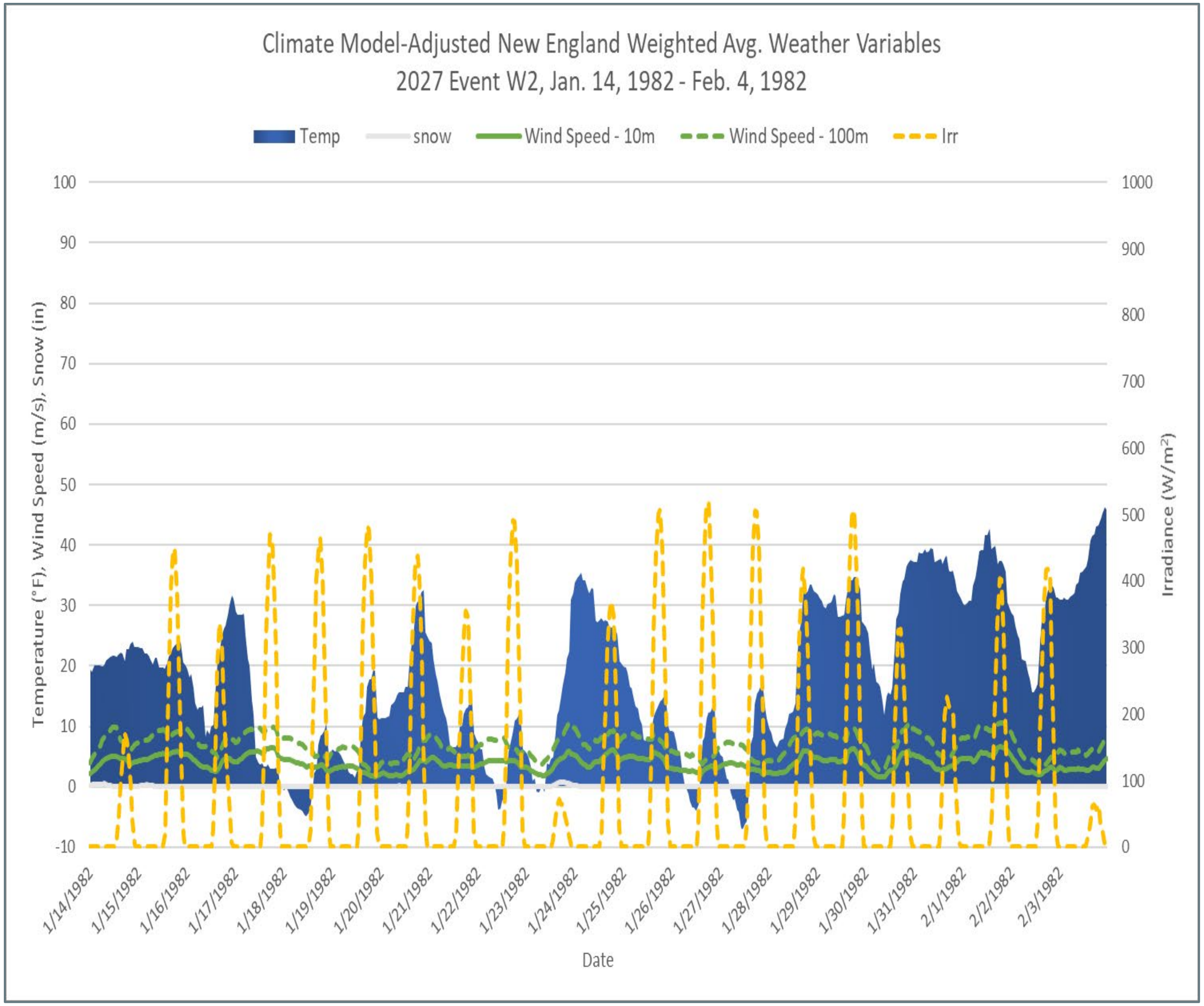
0	0	0	0	0.00%	0.0%

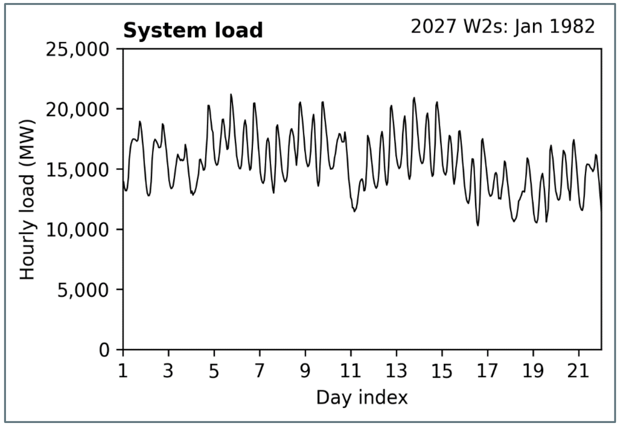
In Worst-Case Energy Shortfalls, Generator Forced Outages Range From ~500 MW/hr to ~5,100 MW/hr



Jan 14, 1982 Winter Event Overview

Multiple Short-Duration Cold Waves Coincident With Low Wind and Very Low Solar



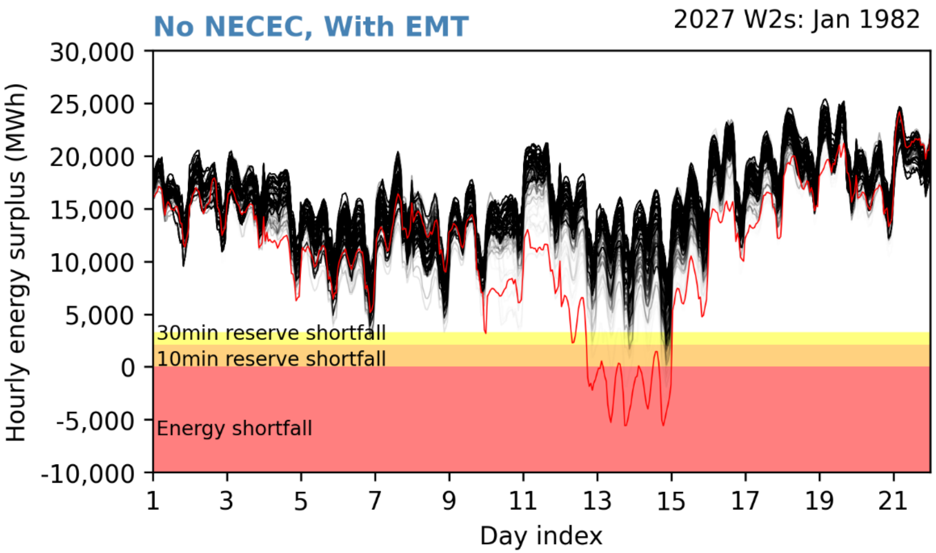


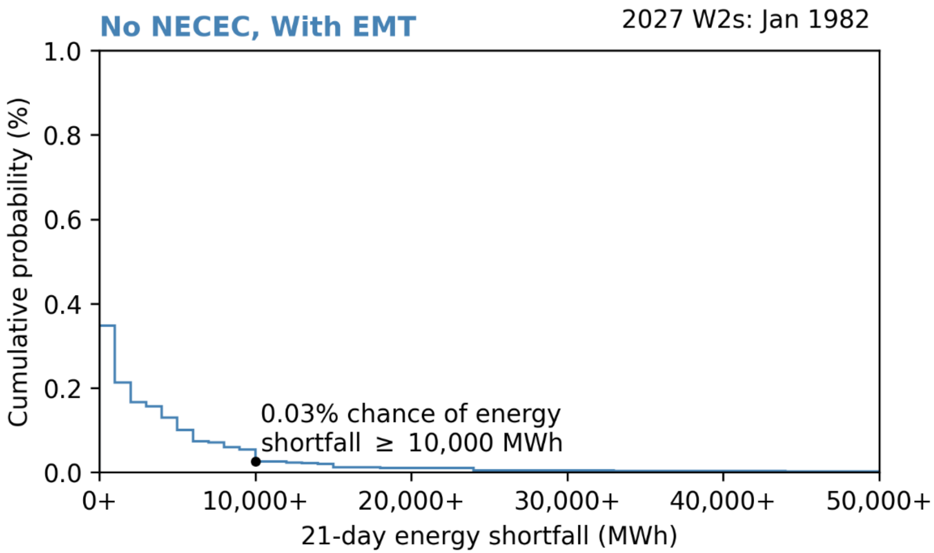
- **Min/Mean/Max (°F):** -7.0/18.4/46.2
- **Mean 100m Wind Speed (m/s):** 6.9
  - Offshore Wind avg. 1,090MW/hr
  - Onshore Wind avg. 510 MW/hr
- **Mean Irradiance (W/m²):** 91.0
  - Utility Scale PV avg. 160 MW/hr
  - BTM PV avg. ~650 MW/hr
- **Avg. Energy From Renewables:** ~2,410 MW/hr
- **Peak Load:** 21,195 MW (day 5)
- **Peak Energy Demand:** ~423,000 MWh (day 5
- **Total 21-Day Energy Demand:** 7.84 TWh
- **Historical Relevance:** One of Top 10 coldest 21-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Jan 14, 1982 Event; Scenario: no NECEC, with EMT

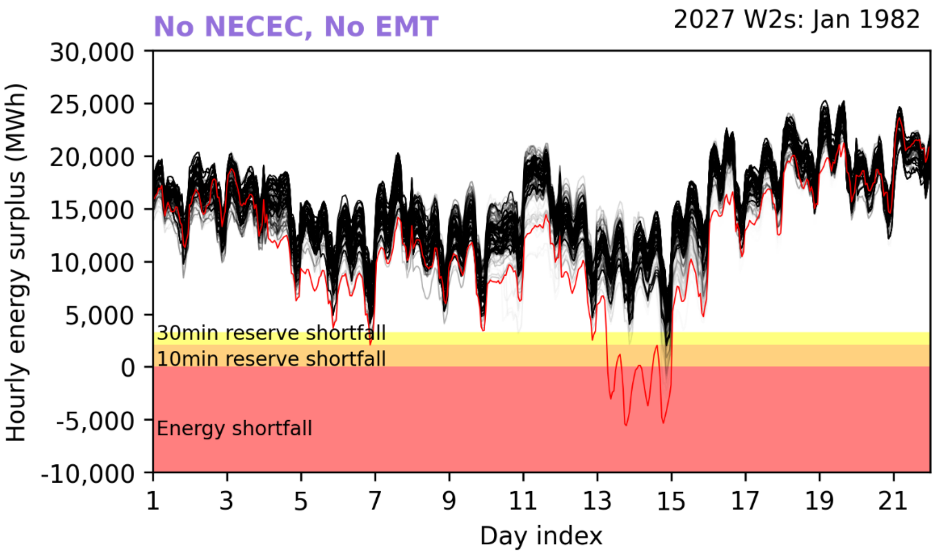


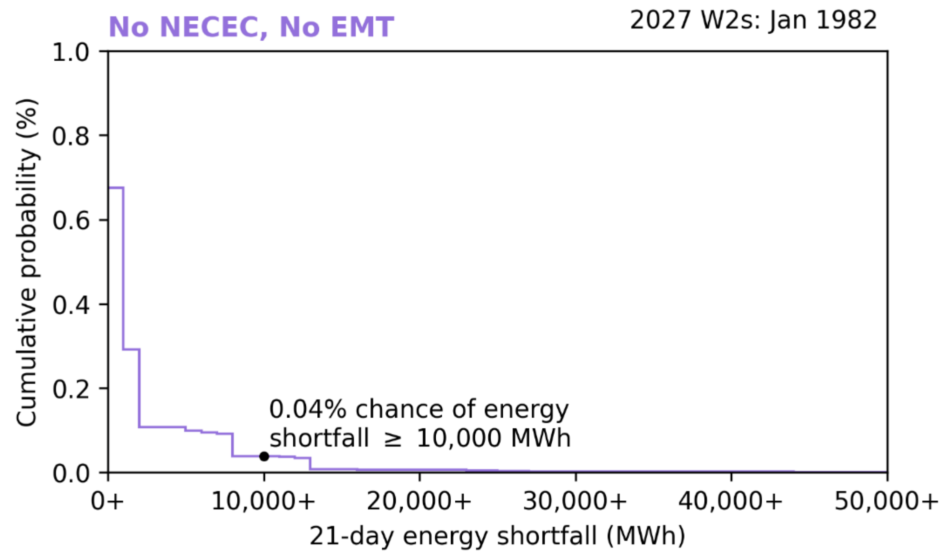


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
139	114,715	32	15	0.35%	0.00004%

Summary of 21-Day Energy Analysis Results

Jan 14, 1982 Event; Scenario: no NECEC, no EMT

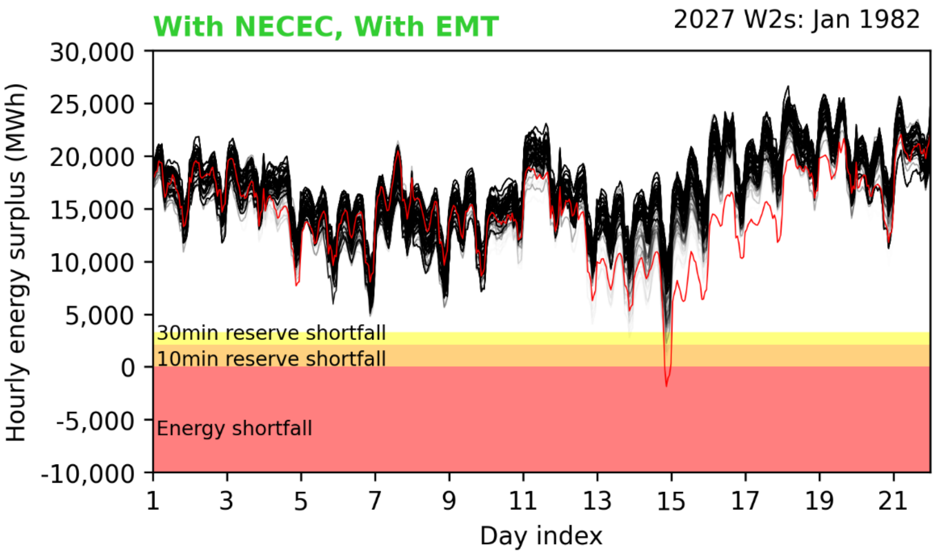


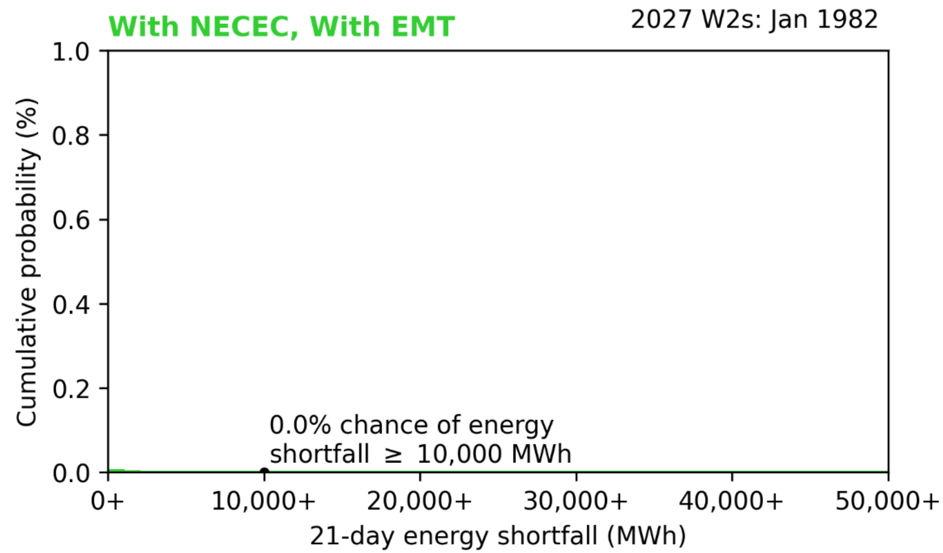


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
95	82,540	72	16	0.68%	0.0006%

Summary of 21-Day Energy Analysis Results

Jan 14, 1982 Event; Scenario: with NECEC, with EMT

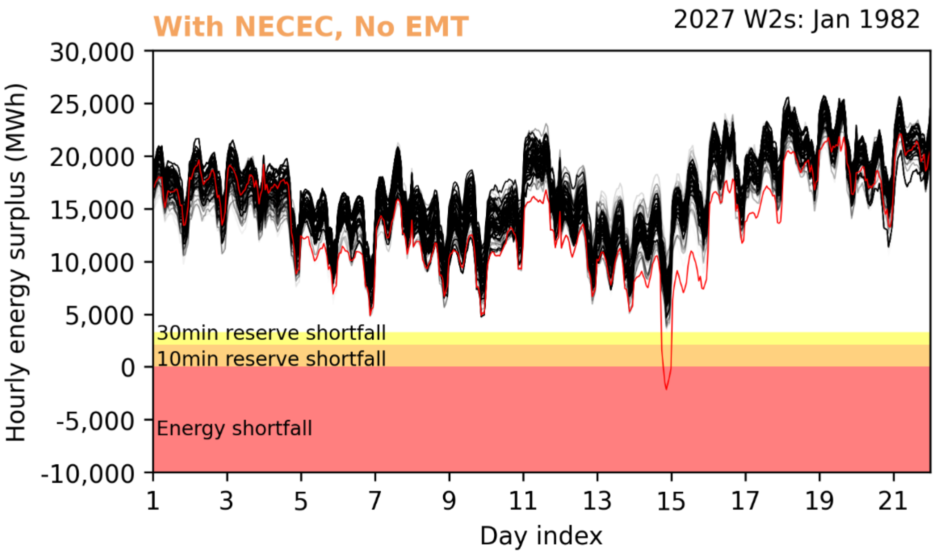


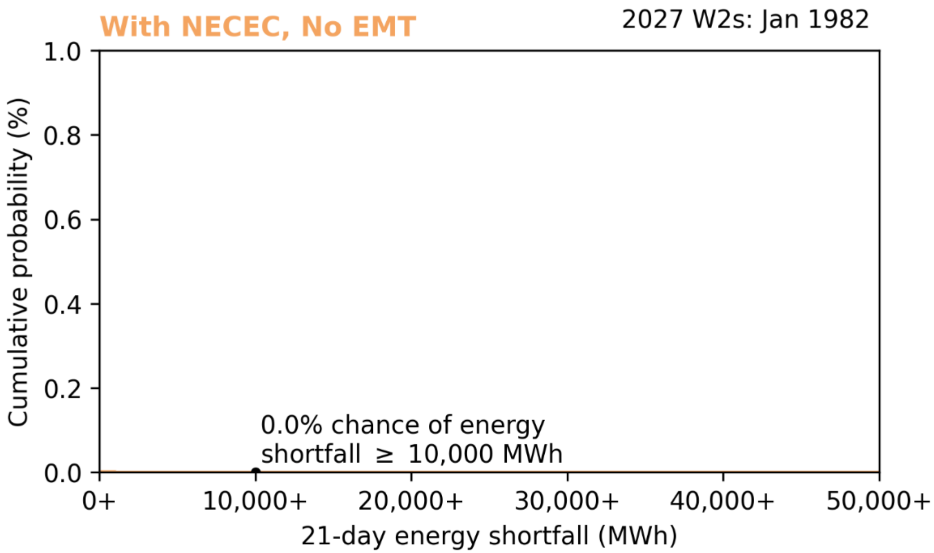


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
7	3,987	320	0	0.004%	0.0006%

Summary of 21-Day Energy Analysis Results

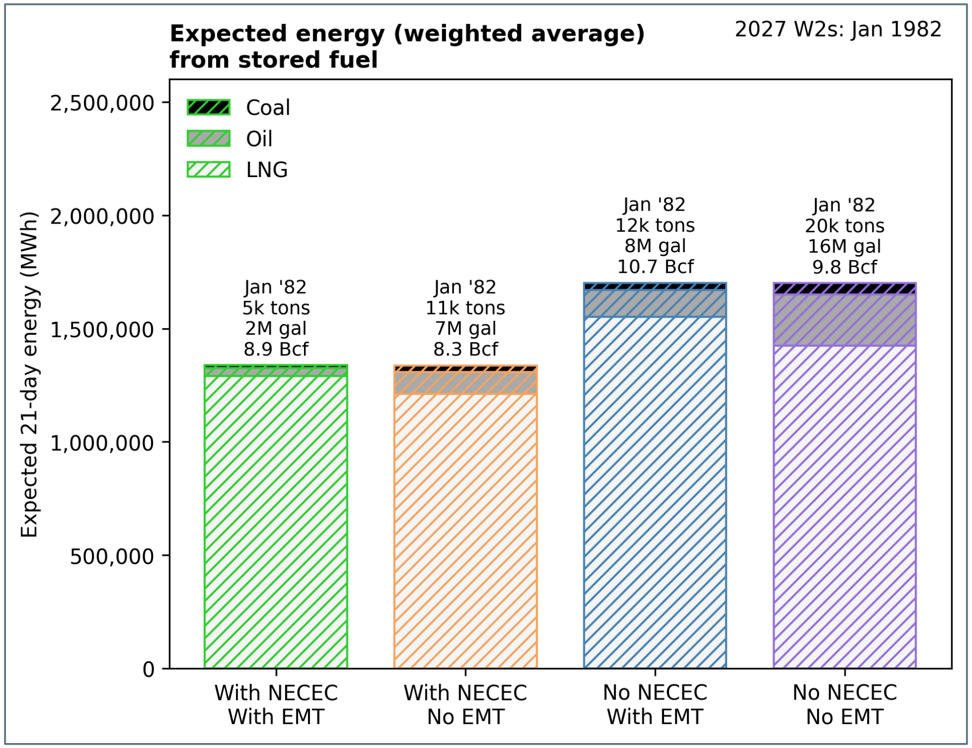
Jan 14, 1982 Event; Scenario: with NECEC, no EMT

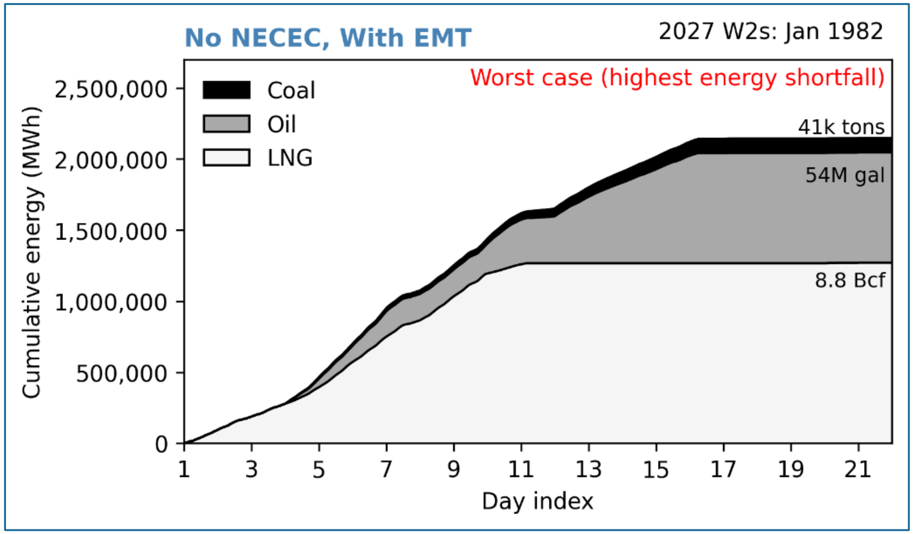


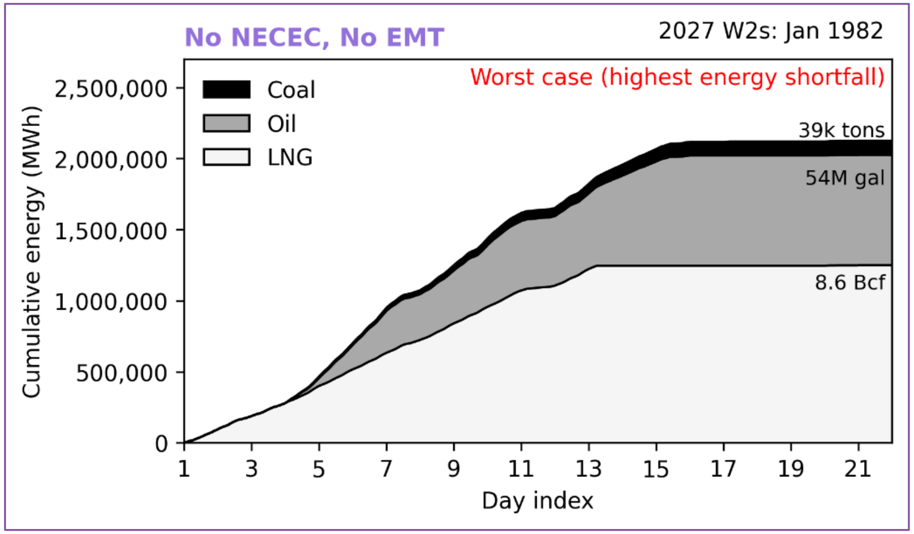


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
3	6,356	610	0	0.0016%	0.0006%

Expected Energy From Stored Fuels is Less Than in the Jan 1961 Event, Though Increase in Stored Fuel Usage Is Still Notable In Worst Cases

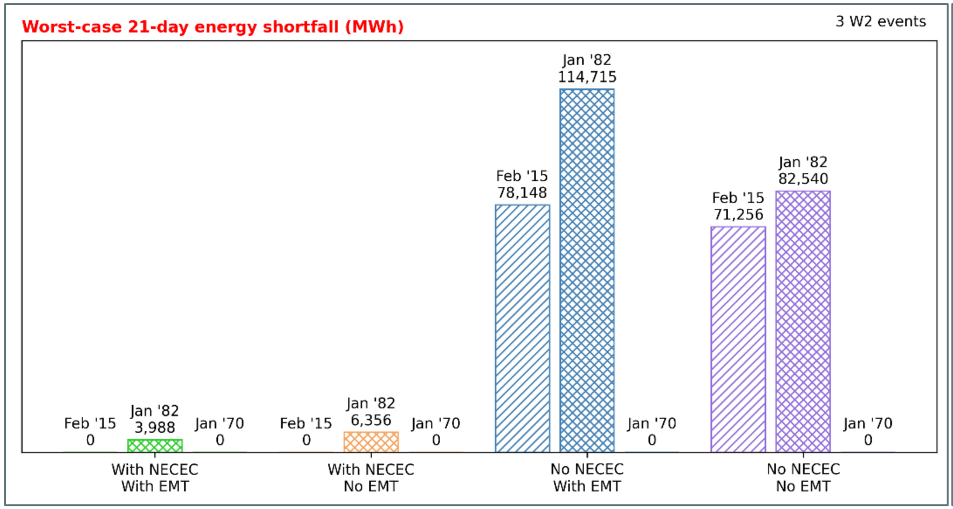


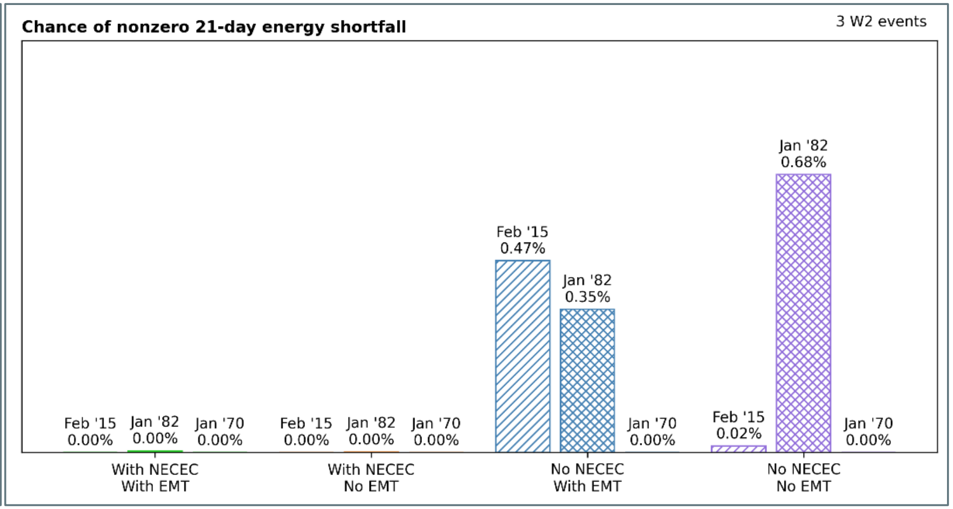




In the figure above, the expected energy from stored fuel is the weighted avg. quantity of stored fuels used across all cases in a given scenario and the figures to the right are for the worst case

2027 Winter Cluster 2
Energy Shortfall Quantities and Probabilities





- Results of the Winter Cluster 2 medoid event (Jan 11, 1970) are included in the figures above; energy shortfall in medoid events is negligible
- Magnitude of energy adequacy risk similar to that of Winter Cluster 1, though probabilities appear significantly lower
- Similar to Winter Cluster 1 findings, preliminary results of Winter Cluster 2 studies reveal:
  - Similar energy adequacy risk with and without EMT in-service; as noted, results with and without EMT are highly dependent on the characteristics of a given event
  - Risks are mitigated by incremental imports from NECEC

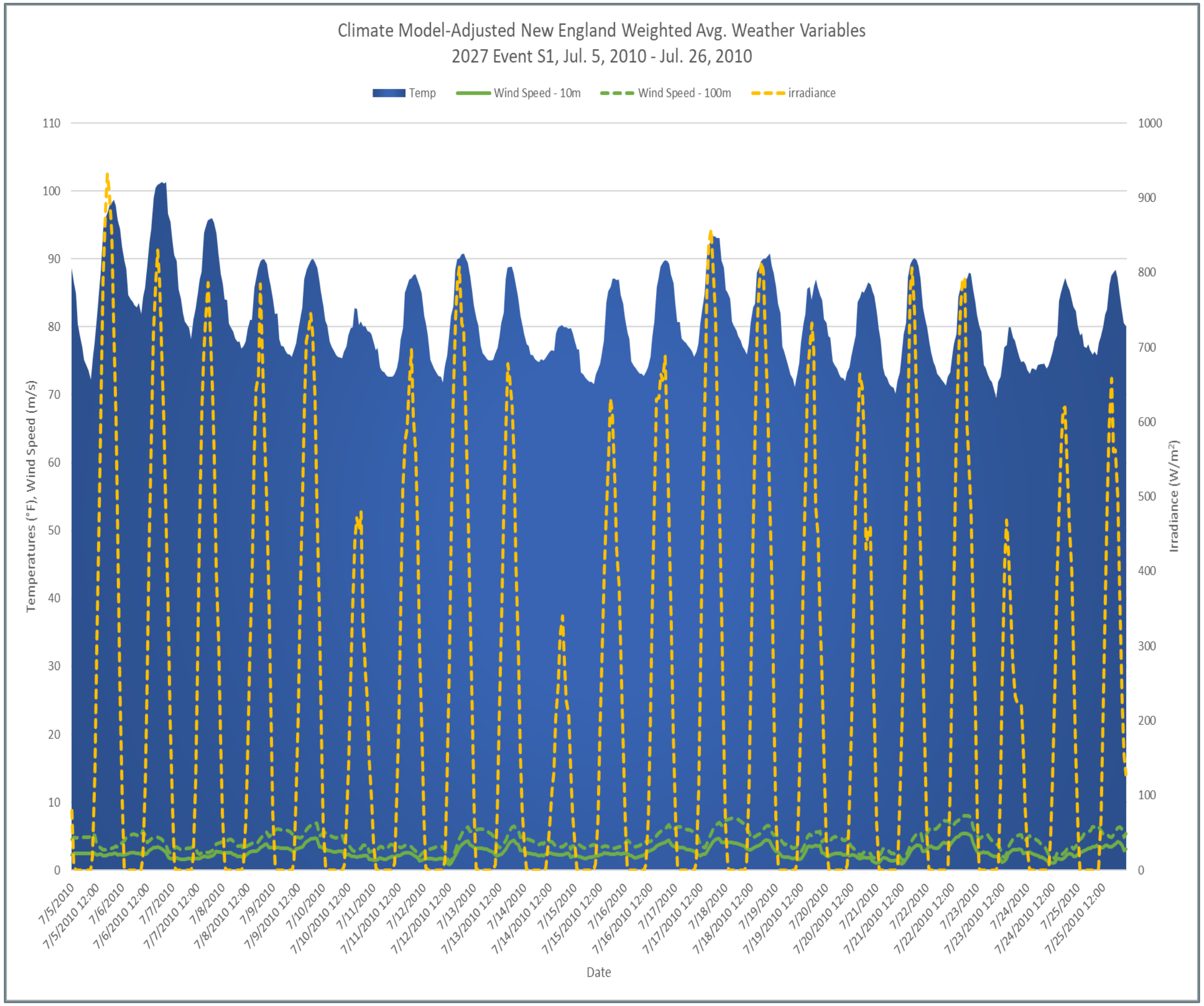
STEP 3: 2027 SUMMER EVENTS RESULTS

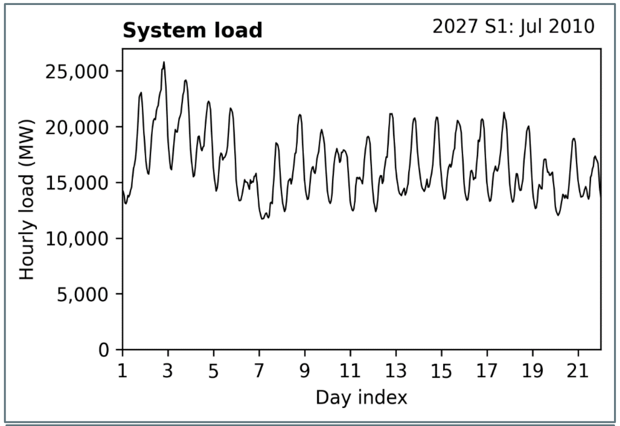
Summary of 2027 Summer Event Studies

- ISO studied the following 2027 Summer Events
  - Summer Cluster 1 (longer-duration events)
    - July 5, 2010 (highest avg. system risk)
    - July 13, 1979 (highest severity index)
    - July 25, 1995 (medoid event)
  - Summer Cluster 2 (short to mid-duration events)
    - July 13, 1979 (highest avg. system risk)
    - July 26, 1984 (highest severity index)
    - Aug 17, 1953 (medoid event)
  - Summer Cluster 3 (moderate temperature events with very low winds and solar)
    - July 28, 2008 (highest avg. system risk and highest severity index)
    - July 19, 1984 (medoid event)
- No energy shortfall was observed in any of these events
- Reserve shortfall was observed only in the July 5, 2010 event; results of those studies are summarized on the following slides

July 5, 2010 Summer Event Overview

Long Duration Heat Wave Coincident With Low Winds





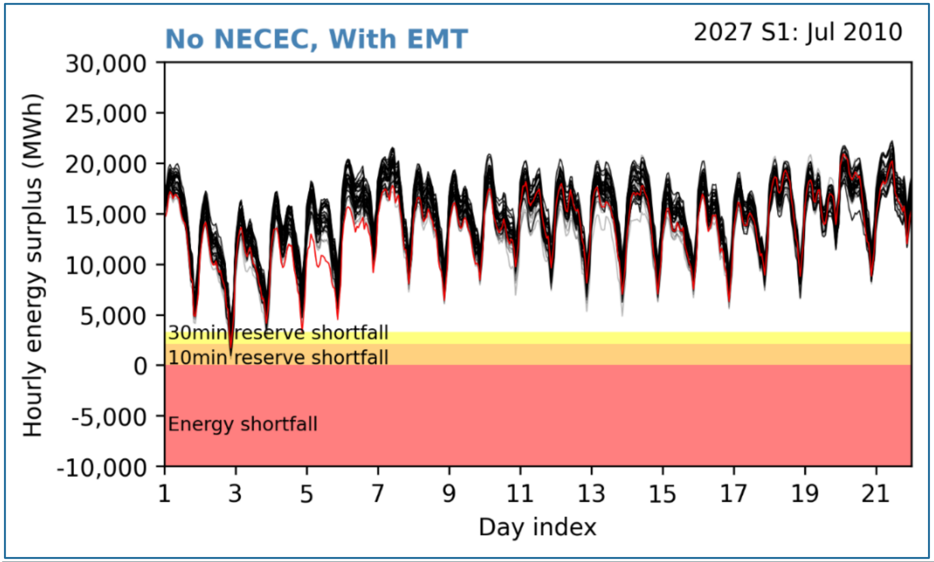
- **Min/Mean/Max (°F):** 69.5/81.4/101.4
- **Mean 100m Wind Speed (m/s):** 4.4
  - Offshore Wind avg. 420 MW/hr
  - Onshore Wind avg. 160 MW/hr
- **Mean Irradiance (W/m²):** 239.9
  - Utility Scale PV avg. 390 MW/hr
  - BTM PV avg. ~1,860 MW/hr
- **Avg. Energy From Renewables:** ~2,830 MW/hr
- **Peak Load:** 25,793 MW (day 2)
- **Peak Energy Demand:** ~499,500 MWh (day 2)
- **Total 21-Day Energy Demand:** 8.38 TWh
- **Historical Relevance:** One of the top 10 warmest 1, 3, 5, 10, and 21-day periods since 1950.

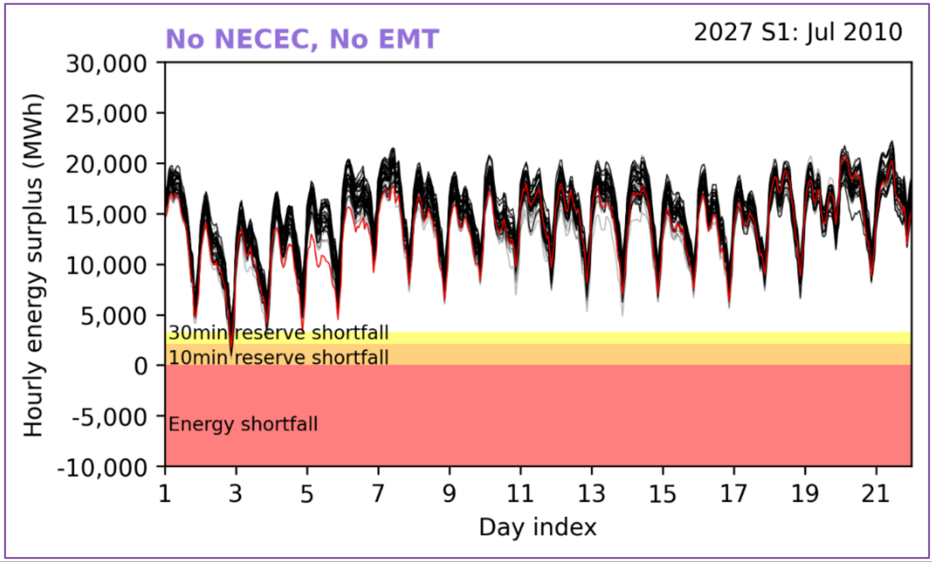
*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

July 5, 2010 Event; Scenarios: No NECEC, With and Without EMT

- Results with and without EMT are similar as there is minimal depletion of stored fuels in any cases; limited amounts of 10 and 30 minute reserve shortfalls occur in the worst cases and no energy shortfall is observed in any cases
- Cases where reserve shortfalls occur are representative of capacity deficiency conditions, which are managed through ISO's Operating Procedure No. 4 (OP-4), Actions During a Capacity Deficiency



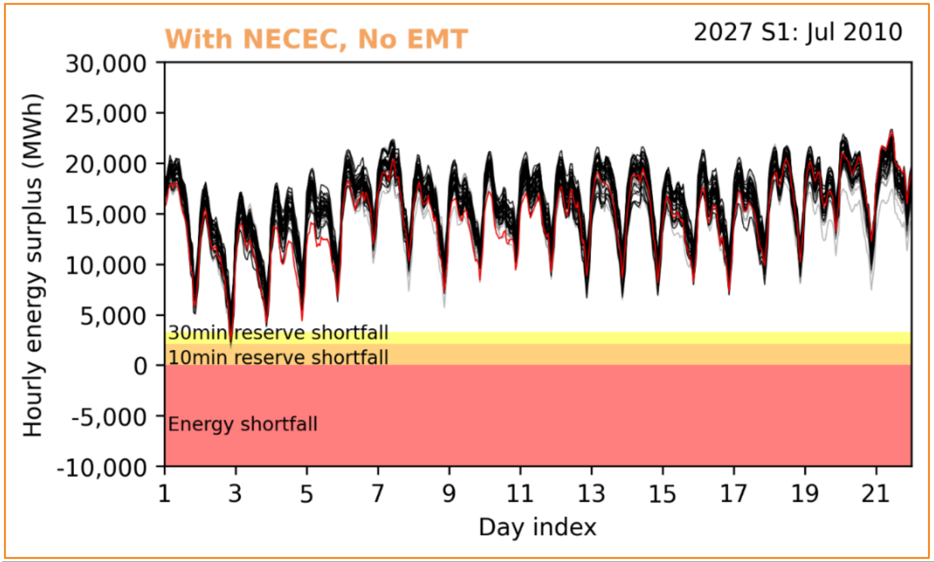


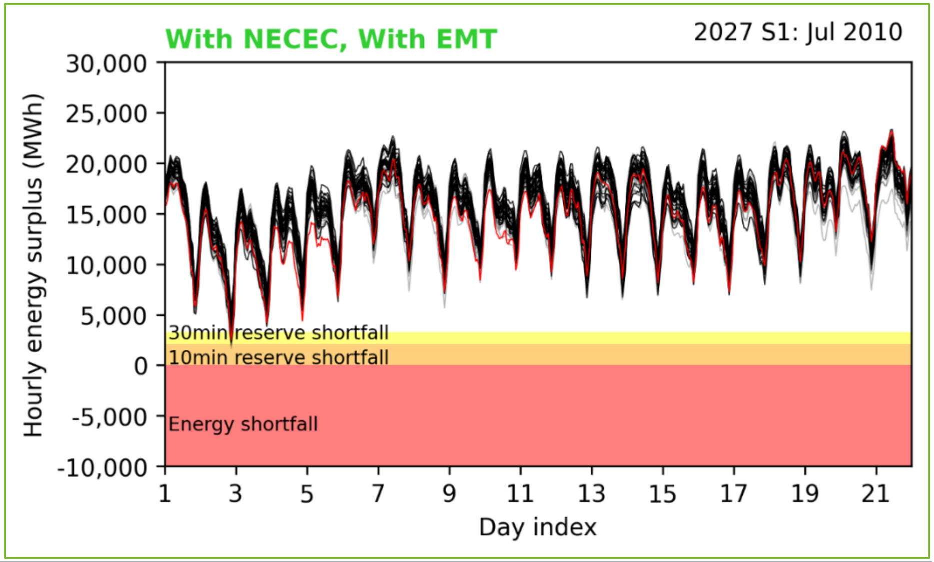
*in the energy surplus chart above (upper-left), the red highlighted trace represents the case that has the highest shortfall amount (MWhs); otherwise, the lower the probability of a case, the lighter its corresponding trace

Summary of 21-Day Energy Analysis Results

July 5, 2010 Event; Scenarios: With NECEC, With and Without EMT

- NECEC helps to reduce reserve shortfalls in worst cases and no energy shortfall is observed in any cases; results with and without EMT are similar as there is minimal depletion of stored fuels in any cases

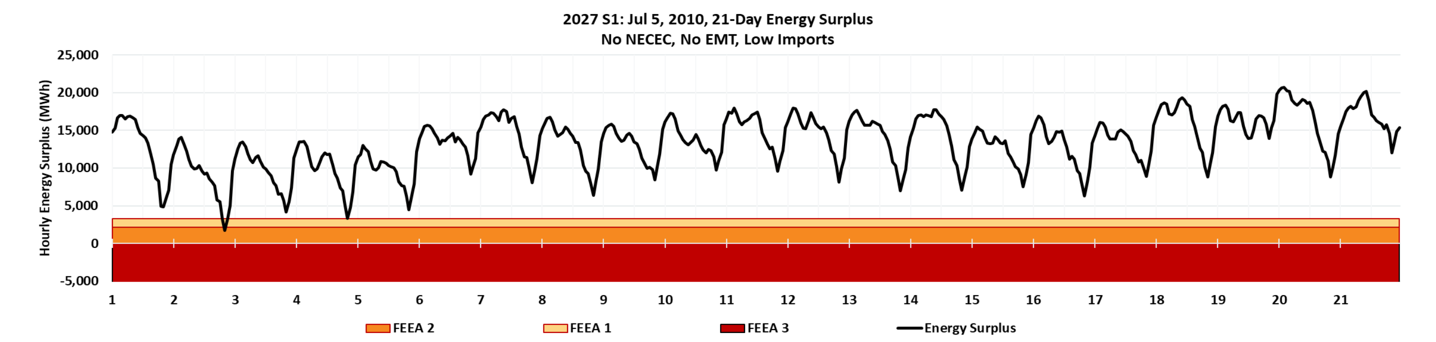


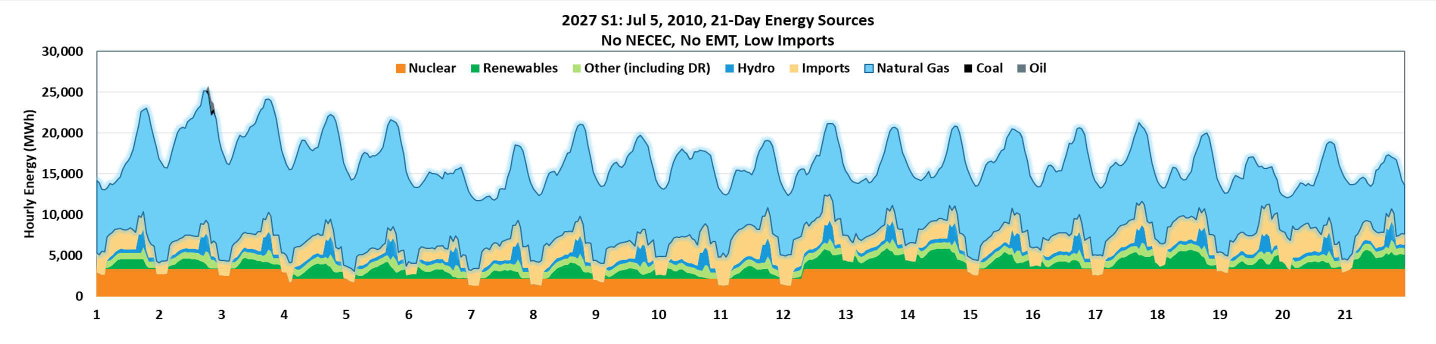


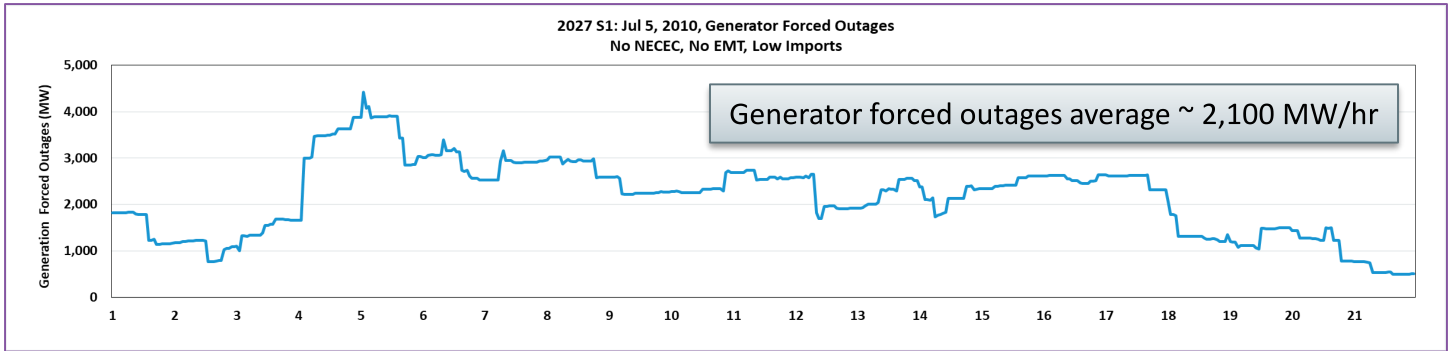
*in the energy surplus chart above (upper-left), the red highlighted trace represents the case that has the highest shortfall amount (MWhs); otherwise, the lower the probability of a case, the lighter its corresponding trace

July 5, 2010 Event Worst-Case Reserve Shortfall

Scenario: no NECEC, no EMT; Case: Low Imports







Energy Shortfall – FEEA3 (MWh)	0
10-Min Reserve Shortfall – FEEA2 (MWh)	1,793
30-Min Reserve Shortfall – FEEA1 (MWh)	4,056
Starting Inventory – LNG (Bcf)	5.4
LNG Replenishment (Bcf), on days 12 & 13	0
LNG Usage (Bcf)	<0.1
Fuel Oil Starting Inventory (gal)	~128 M
Fuel Oil Replenishment (gal), as needed	~0.57 M
Fuel Oil Usage (gal)	~0.59 M

2032 STUDY YEAR RESULTS

Resource and Demand Assumptions for Study Year 2032

- 2032 baseline studies include resources that obtained a CSO in FCA 16, resources that delisted in FCA 16 and didn't obtain a CSO, and state-sponsored resources under contract or have been selected under recent RFP's
  - ISO's 2032 baseline studies assume all FCA 16 cleared resources, including Millstone Station, which is currently on a state contract
- 2032 studies incorporate ISO's 2022 CELT heating and transportation electrification forecasts

Resource and Demand Assumptions		
	2027 Study Year	2032 Study Year
CELT Load Forecast Year	2022	2022
FCA Results	FCA 16	FCA 16
Retired Capacity*	2,100	2,100 (no change from 2027)
Offshore Wind Capacity*	1,600	4,800
Storage Battery Capacity*	1,450	1,450 (no change from 2027)
Utility-scale PV Capacity*	1,250	1,250 (no change from 2027)
BTM PV Capacity*	9,500	12,000

**capacity values listed in the table above, in MW, are based on nameplate and are approximate*

Winter Weather Events Selected By Risk Screening Model For Study Year 2032

- The 2032 winter events selected for study are characterized by short and long-duration extreme cold, low winds, and low solar irradiance
- This section reviews the following 2032 winter events:
  - Winter Cluster 1 (longer-duration events)
    - Jan 22, 1961 (event with highest average system risk*)
    - Jan 12, 2004 (event with highest severity index*)
  - Winter Cluster 2 (shorter-duration events)
    - Feb 14, 2015 (event with highest average system risk)
    - Jan 7, 1982 (event with highest severity index)
  - Medoid events for each cluster were also studied; results are briefly summarized later in this presentation
  - Note that the Jan 22, 1961 and Feb 14, 2015 events were also included in 2027 winter studies and, where possible, changes from 2027 to 2032 are highlighted

*Average System Risk and Severity Index are metrics calculated by EPRI's Risk Screening Model; these metrics are used to rank events and aid in the selection of events for study

Summer Weather Events Selected By Risk Screening Model For Study Year 2032

- Summer 2032 events selected for study are characterized by short to long-duration heat waves with low winds and low solar irradiance:
  - Summer Cluster 1 – characterized by longer-duration events
    - July 13, 1979 (highest avg. system risk and severity index*)
    - July 5, 1994 (medoid event)
  - Summer Cluster 2 – characterized by short to mid-duration events
    - August 2, 1984 (highest avg. system risk)
    - July 26, 1984 (highest severity index)
    - July 11, 1995 (medoid event)
  - Summer Cluster 3 – characterized by events with moderate summer temperatures with very low winds and solar
    - July 28, 2008 (highest avg. system risk and severity index)
    - August 6, 2001 (medoid event)

*Average System Risk and Severity Index are metrics calculated by EPRI's Risk Screening Model; these metrics are used to rank events and aid in the selection of events for study

STEP 3: 2032 WINTER CLUSTER 1 (W1) RESULTS

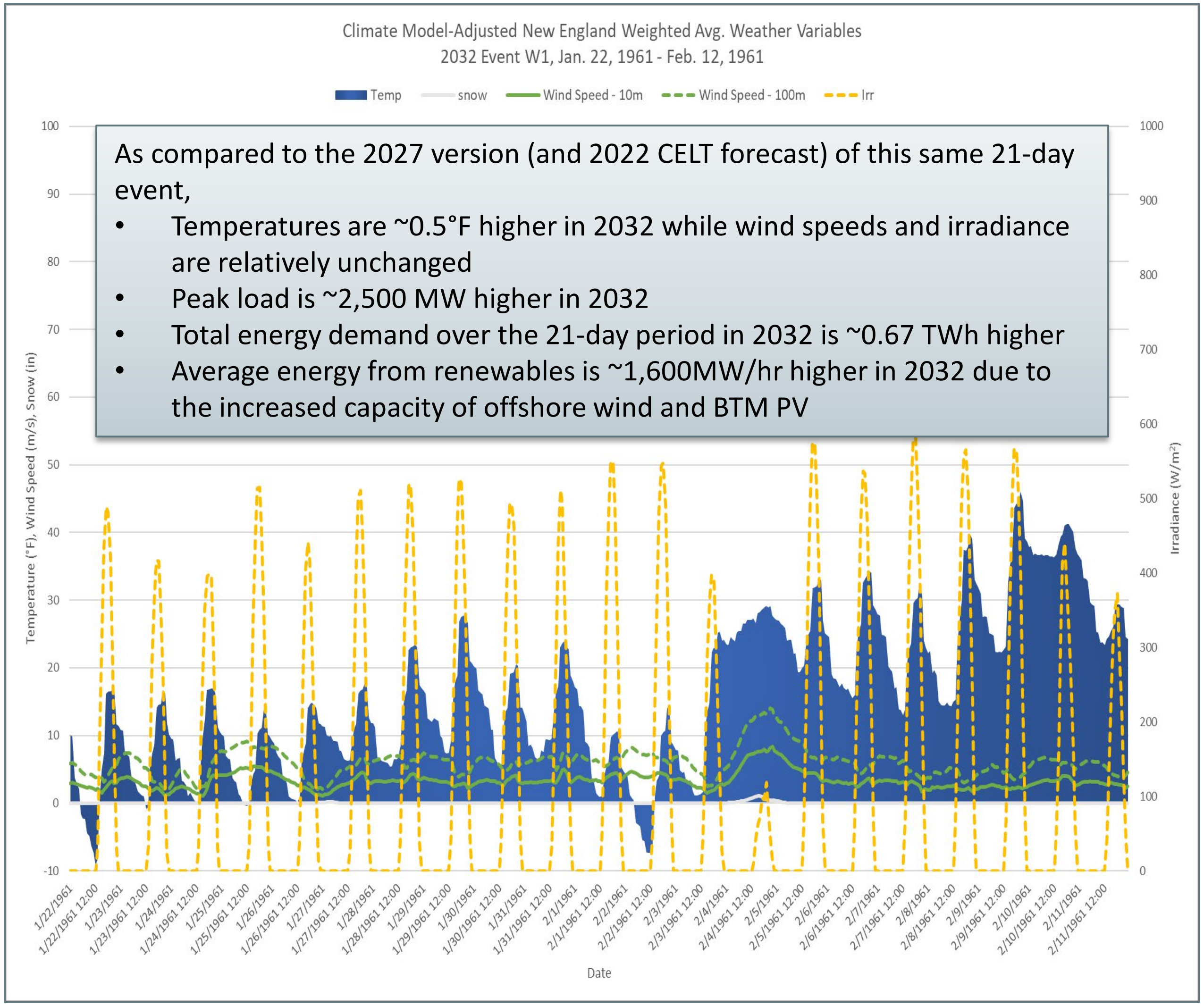
Jan 22, 1961 (highest average system risk event) & Jan 12, 2004 (highest severity index event)

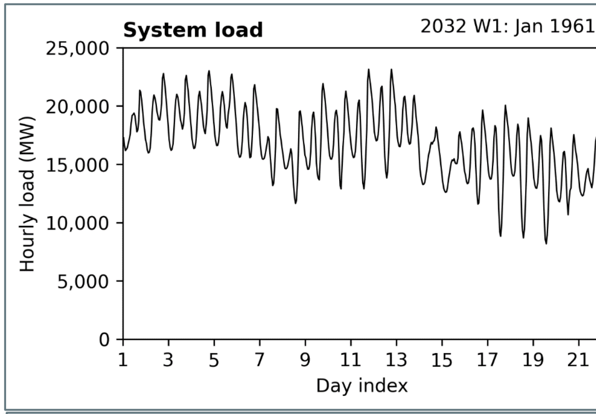
Jan 22, 1961 Winter Event Overview

~12-Day Cold Wave Coincident With Low Wind and Very Low Solar

As compared to the 2027 version (and 2022 CELT forecast) of this same 21-day event,

- Temperatures are ~0.5°F higher in 2032 while wind speeds and irradiance are relatively unchanged
- Peak load is ~2,500 MW higher in 2032
- Total energy demand over the 21-day period in 2032 is ~0.67 TWh higher
- Average energy from renewables is ~1,600MW/hr higher in 2032 due to the increased capacity of offshore wind and BTM PV



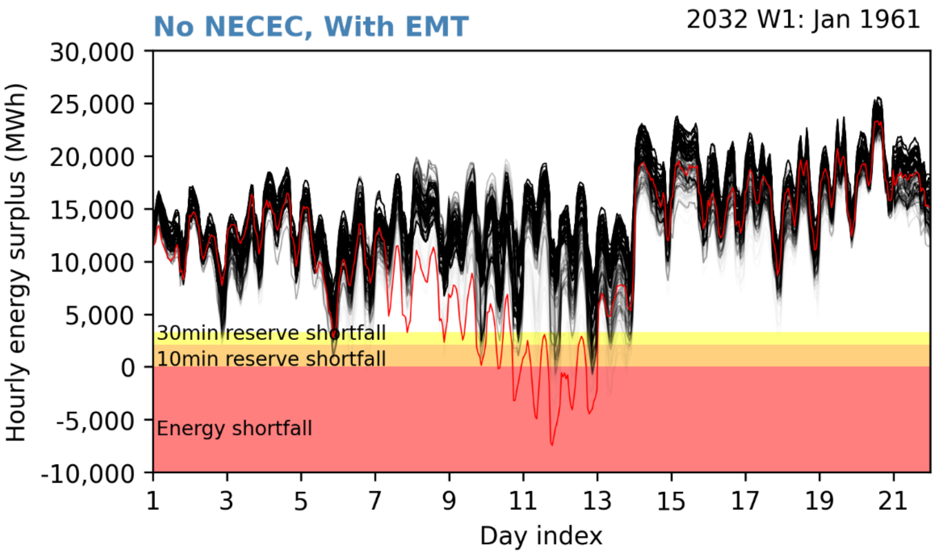


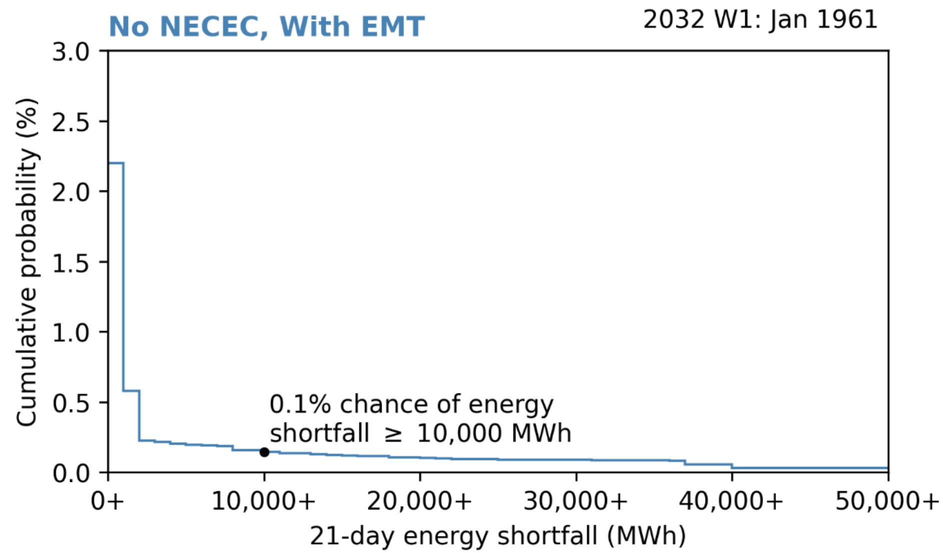
- **Min/Mean/Max (°F):** -9.2/16.2/46.0
- **Mean 100m Wind Speed (m/s):** 6.0
  - Offshore Wind avg. ~2,225 MW/hr
  - Onshore Wind avg. ~340 MW/hr
- **Mean Irradiance (W/m²):** 118.8
  - Utility Scale PV avg. ~220 MW/hr
  - BTM PV avg. ~1,020 MW/hr
- **Avg. Energy From Renewables:** ~3,805 MW/hr
- **Peak Load:** 23,144 MW (day 11)
- **Peak Daily Energy Demand:** ~466,000 MWh (day 5)
- **Total 21-Day Energy Demand:** 8.49 TWh
- **Historical Relevance:** Coldest 21-day period since 1950; includes two of the top 10 coldest 5-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: no NECEC, with EMT



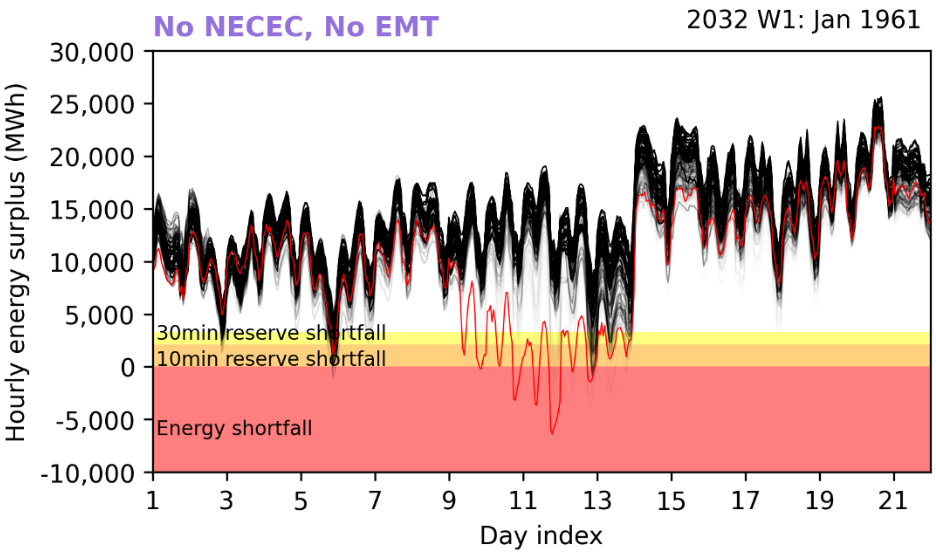


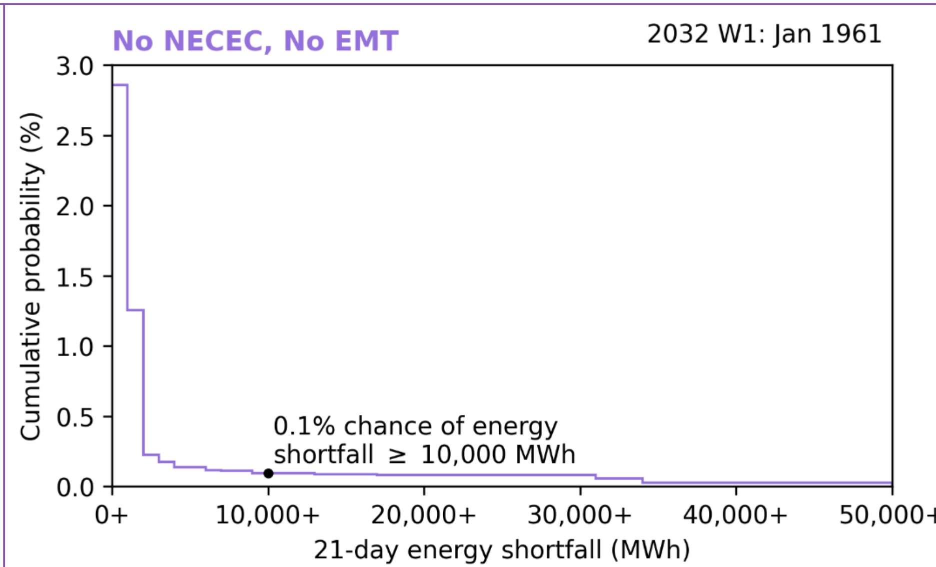
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	232	115,642	21	69	2.20%	0.00055%
2027*	233	111,353	36	421	7.60%	0.00055%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: no NECEC, no EMT



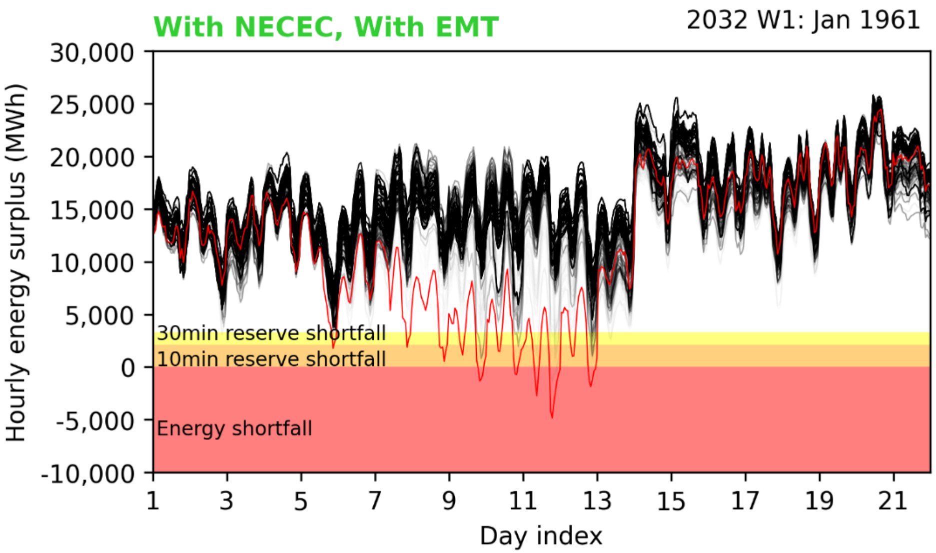


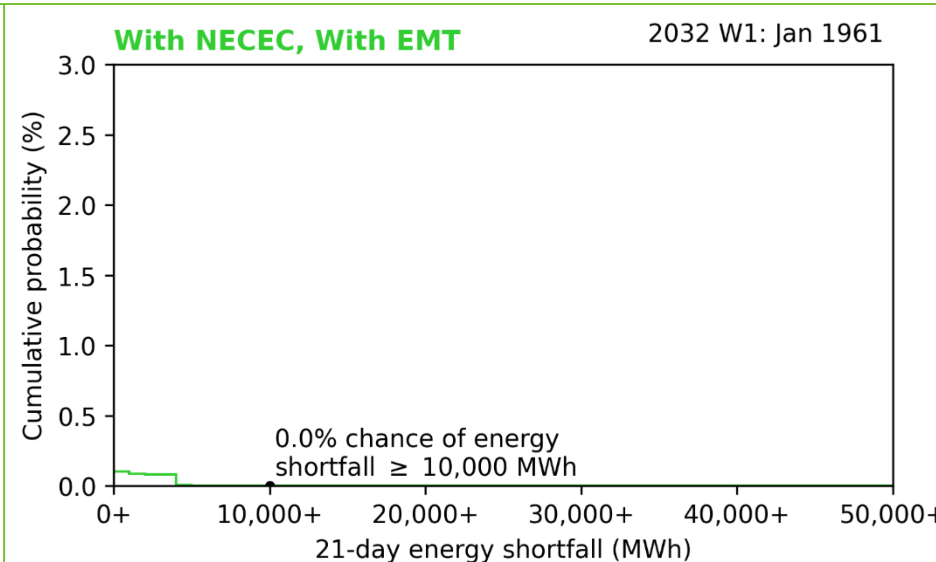
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	209	63,781	1	57	2.90%	0.0000038%
2027*	172	95,888	1	202	2.30%	0.00055%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: with NECEC, with EMT



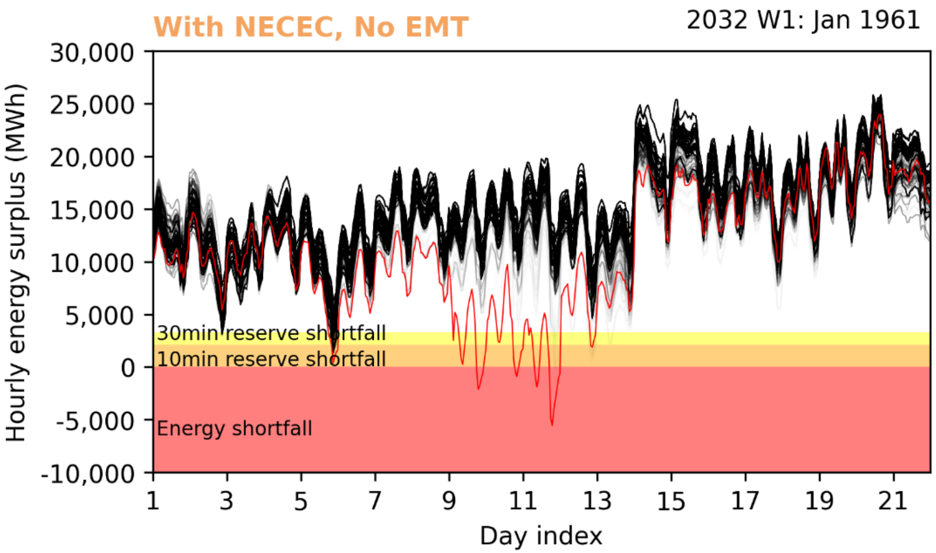


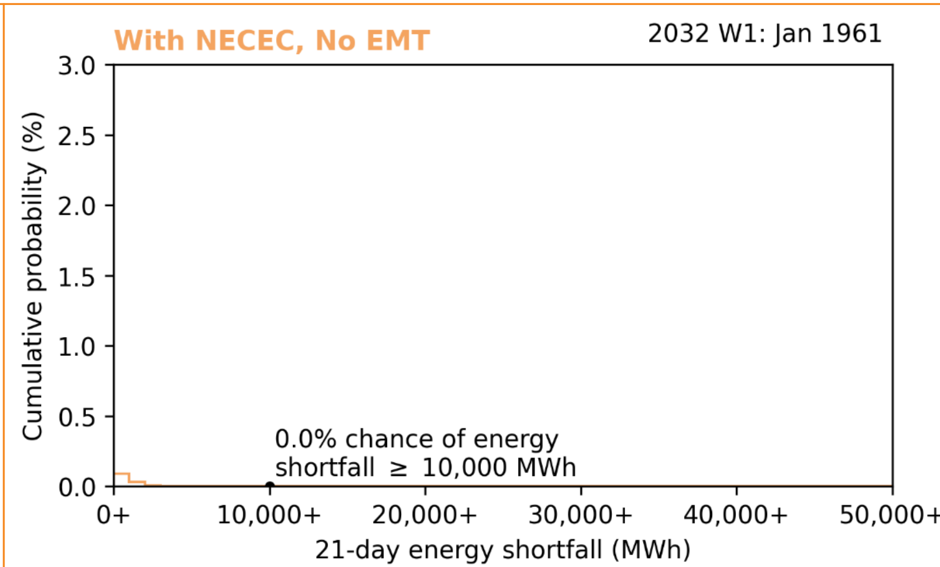
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	57	31,974	29	3	0.10%	0.0000038%
2027*	30	68,932	1	113	0.67%	0.0044%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Summary of 21-Day Energy Analysis Results

Jan 22, 1961 Event; Scenario: with NECEC, no EMT

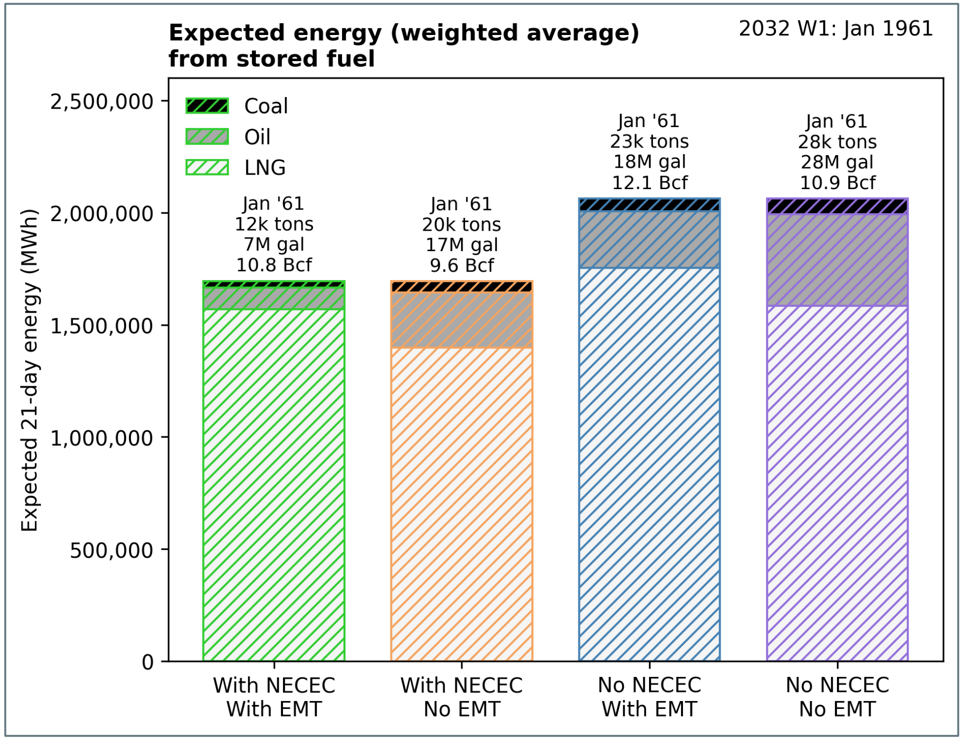




Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	30	33,019	47	1	0.09%	0.0000038%
2027*	25	53,518	143	28	0.64%	0.0044%

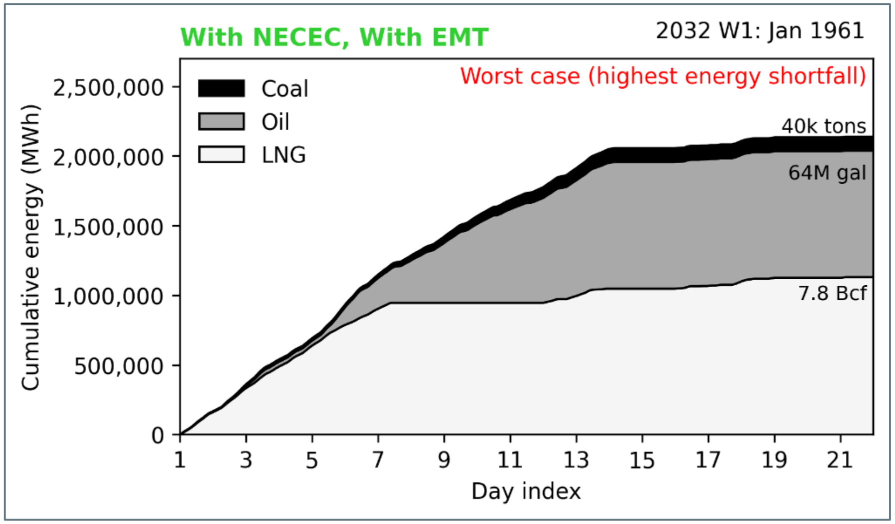
*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

As Seen in 2027 Studies, In Worst Case Energy Shortfalls, Increases in Stored Fuel Usage Are Notable



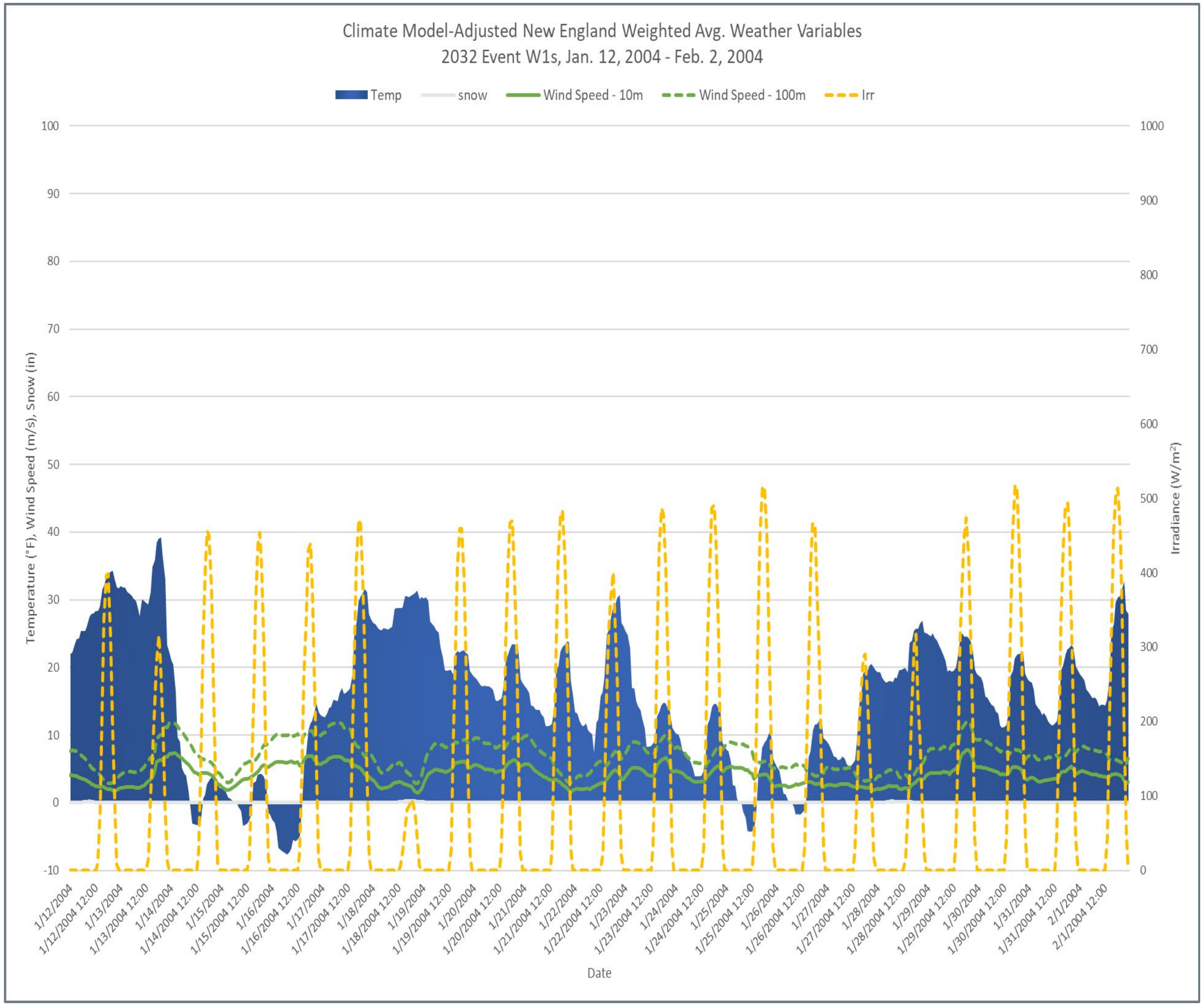
In the figure above, the expected energy from stored fuel is the weighted avg. quantity of stored fuels used across all cases in a given scenario and the figure to the right are for the worst case

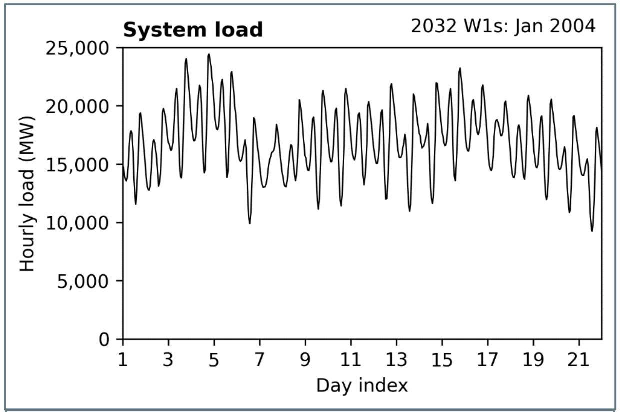
- Similar to results of 2027 studies of the same event, stored fuel usage in the 2032 baseline studies of this event increases significantly in worst cases
- As shown in the figure below, increased energy from stored fuels is notable even in scenarios with NECEC in-service



Jan 12, 2004 Winter Event Overview

~10-Day Cold Wave Coincident With Low Winds and Low Solar



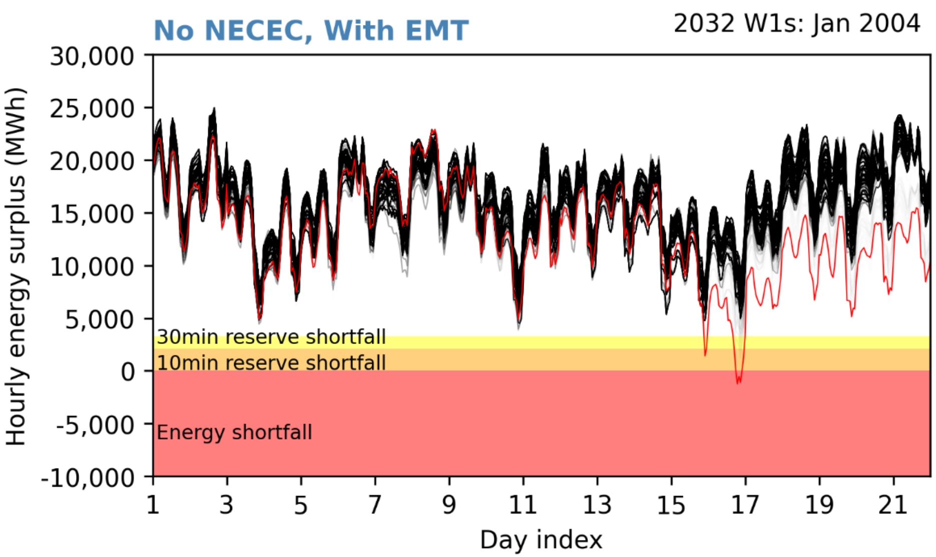


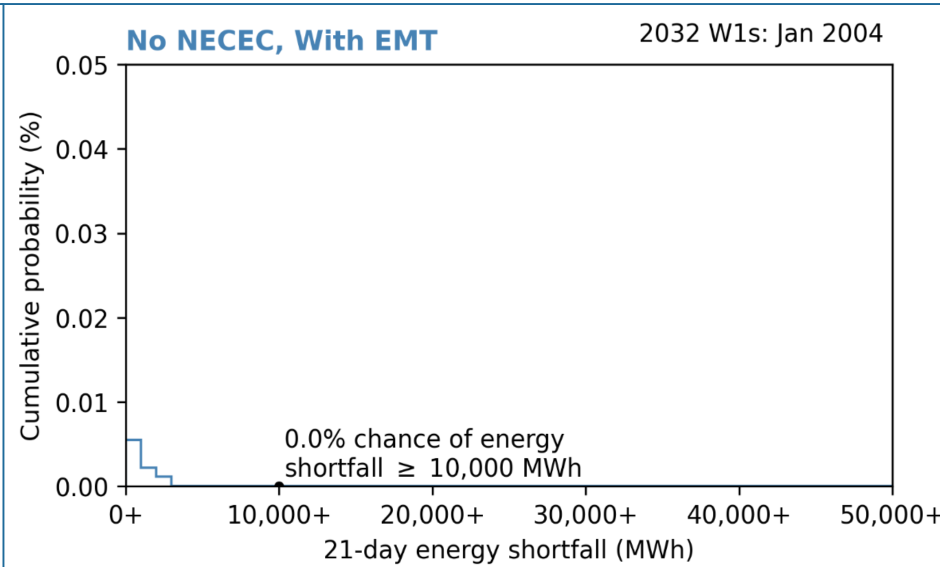
- **Min/Mean/Max (°F):** -7.6/15.7/39.3
- **Mean 100m Wind Speed (m/s):** 7.0
  - Offshore Wind avg. ~3,090 MW/hr
  - Onshore Wind avg. ~535 MW/hr
- **Mean Irradiance (W/m²):** 102.0
  - Utility Scale PV avg. ~200 MW/hr
  - BTM PV avg. ~1,300 MW/hr
- **Avg. Energy From Renewables:** ~5,125 MW/hr
- **Peak Load:** 24,429 MW (day 4)
- **Peak Daily Energy Demand:** ~468,000 MWh (day 4)
- **Total 21-Day Energy Demand:** 8.49 TWh
- **Historical Relevance:** The actual weather during this stretch was included in the top ten coldest 21-day and 10-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Jan 12, 2004 Event; Scenario: no NECEC, with EMT

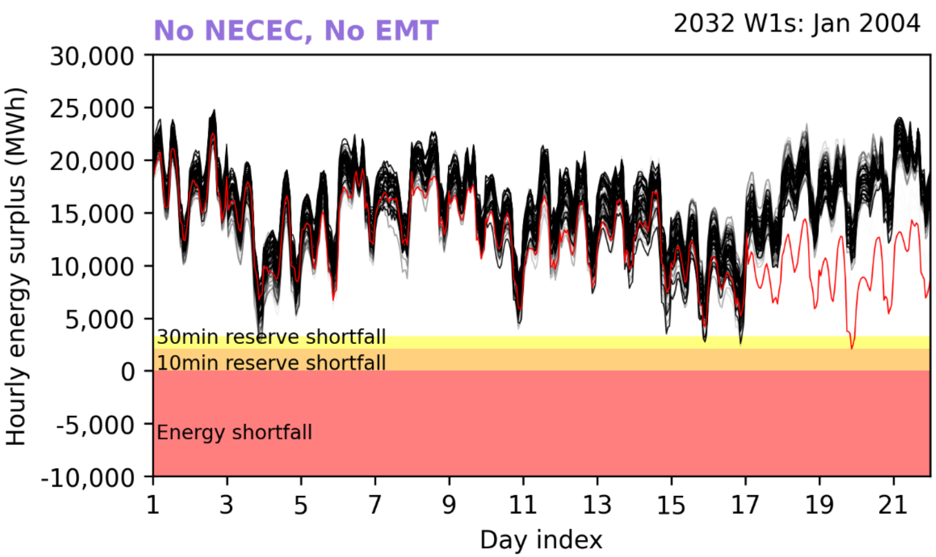


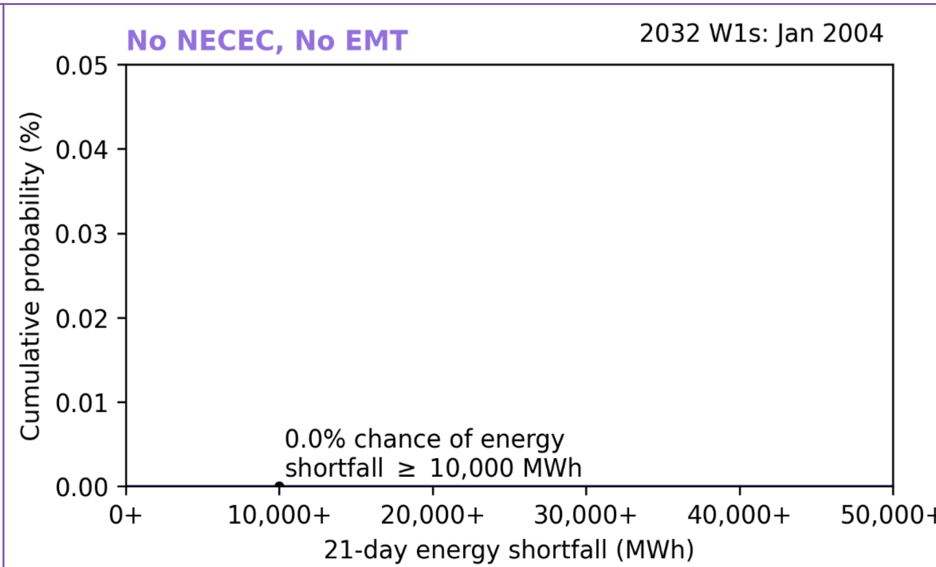


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
10	2,906	25	0	0.01%	0.00055%

Summary of 21-Day Energy Analysis Results

Jan 12, 2004 Event; Scenario: no NECEC, no EMT

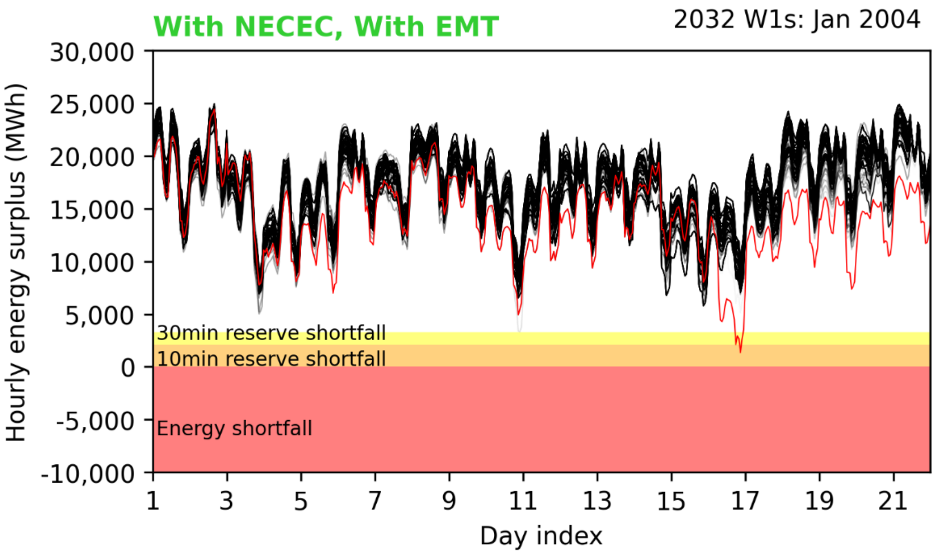


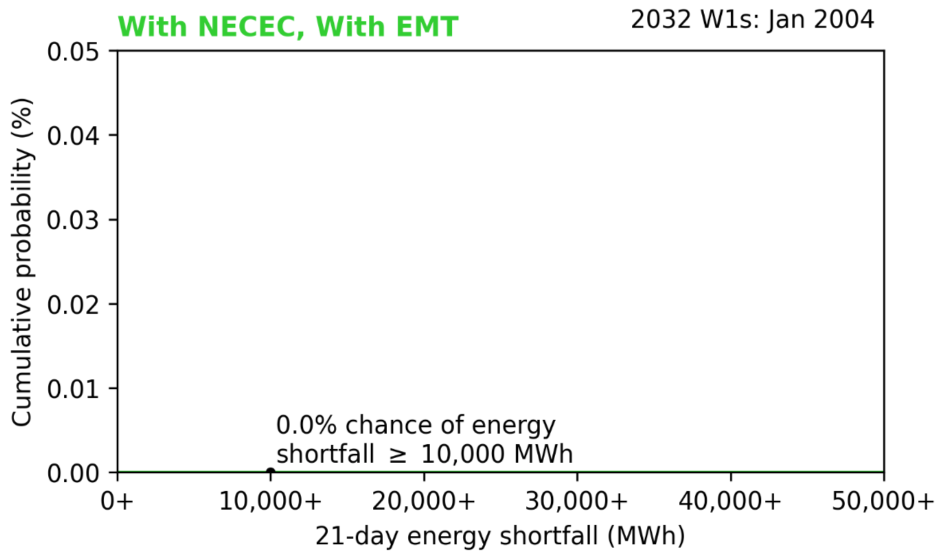


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

Summary of 21-Day Energy Analysis Results

Jan 12, 2004 Event; Scenario: with NECEC, with EMT

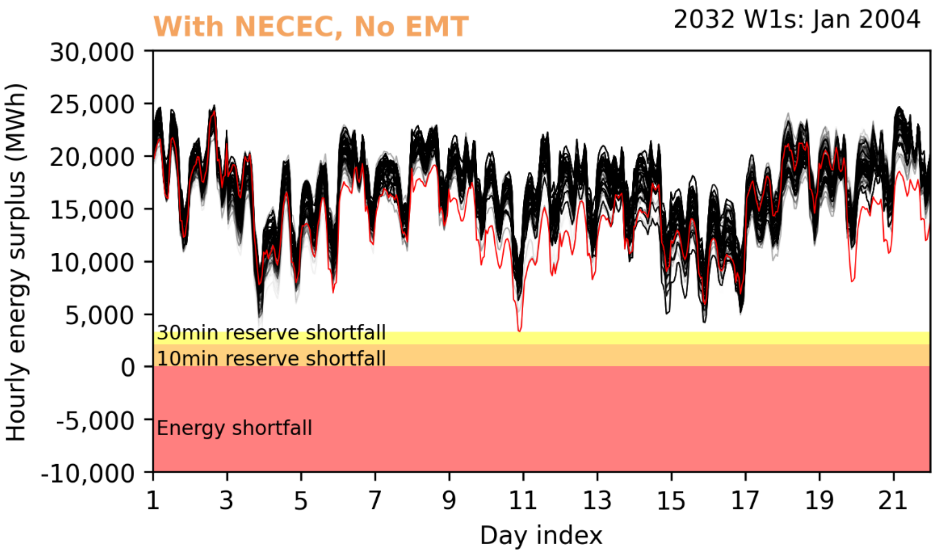


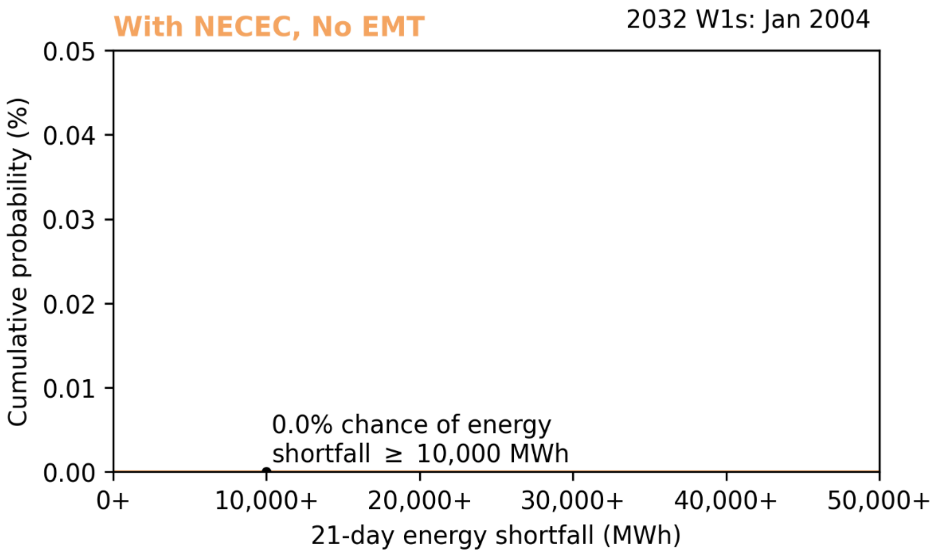


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

Summary of 21-Day Energy Analysis Results

Jan 12, 2004 Event; Scenario: with NECEC, no EMT

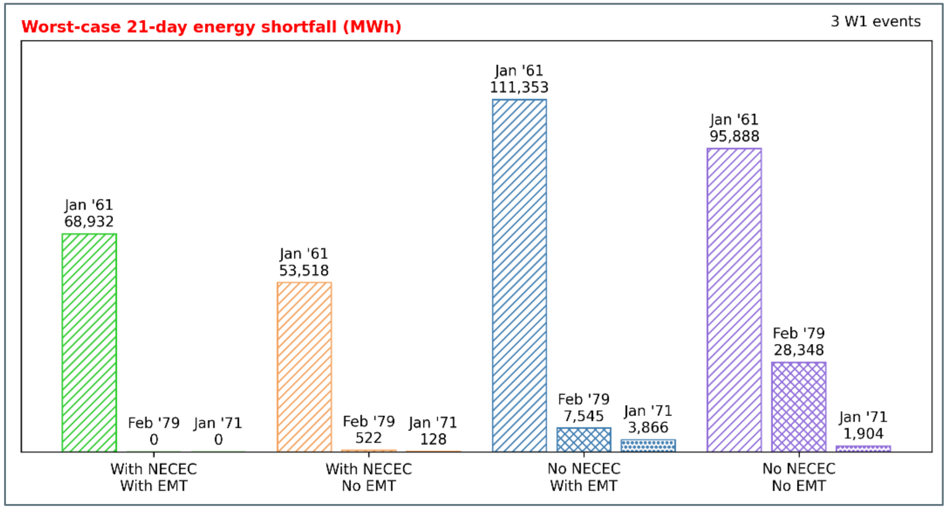




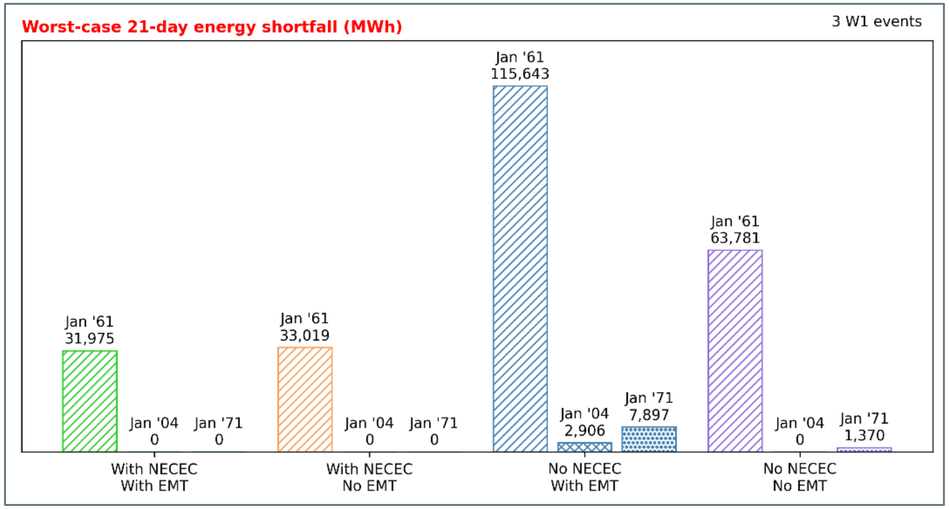
# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

2027 and 2032 Winter Cluster 1 Events - Comparison of Energy Shortfall Quantities

2027 Winter Cluster 1 Events



2032 Winter Cluster 1 Events



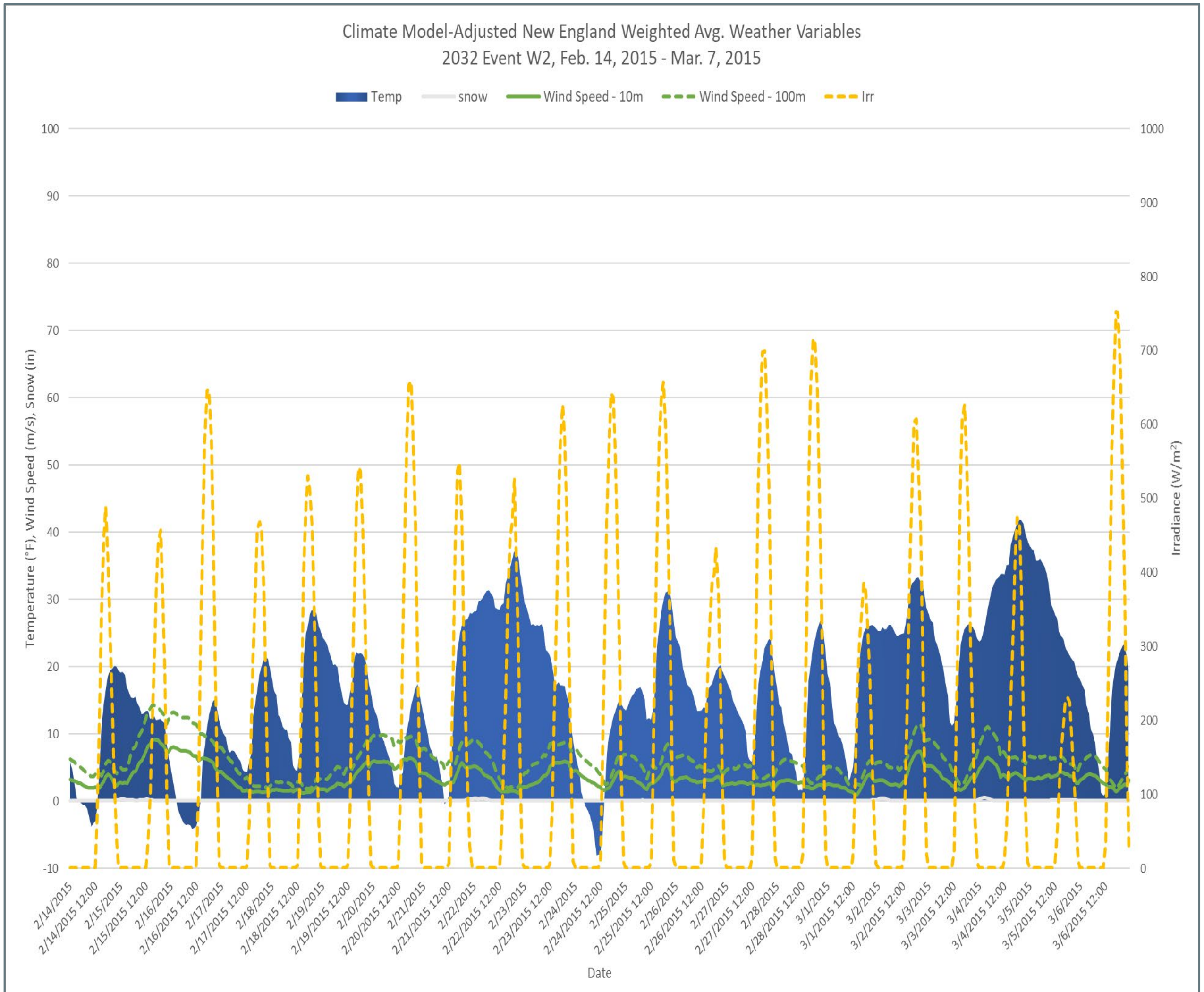
- Results of the Winter Cluster 1 medoid event (Jan 15, 1971) are included in the figures above; energy shortfall risk in the medoid events is negligible
- Results of 2032 Winter Cluster 1 baseline studies reveal energy shortfall risk comparable to 2027 event studies

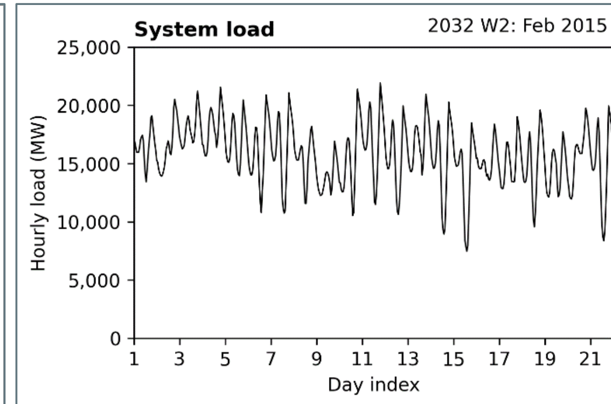
STEP 3: 2032 WINTER CLUSTER 2 (W2) RESULTS

Feb 14, 2015 (highest average system risk event) & Jan 7, 1982 (highest severity index event)

Feb 14, 2015 Winter Event Overview

Multiple Short-Duration Cold Waves Coincident With Low Wind and Low Solar



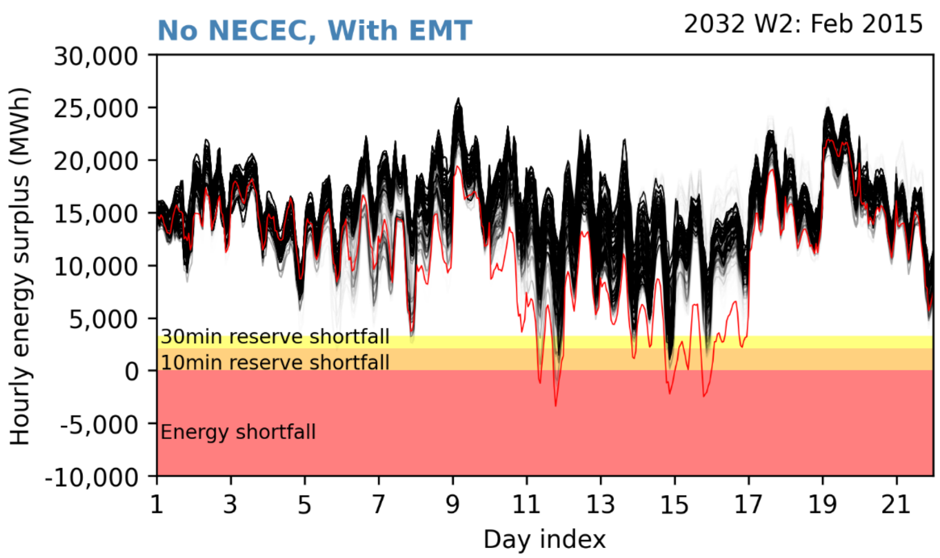


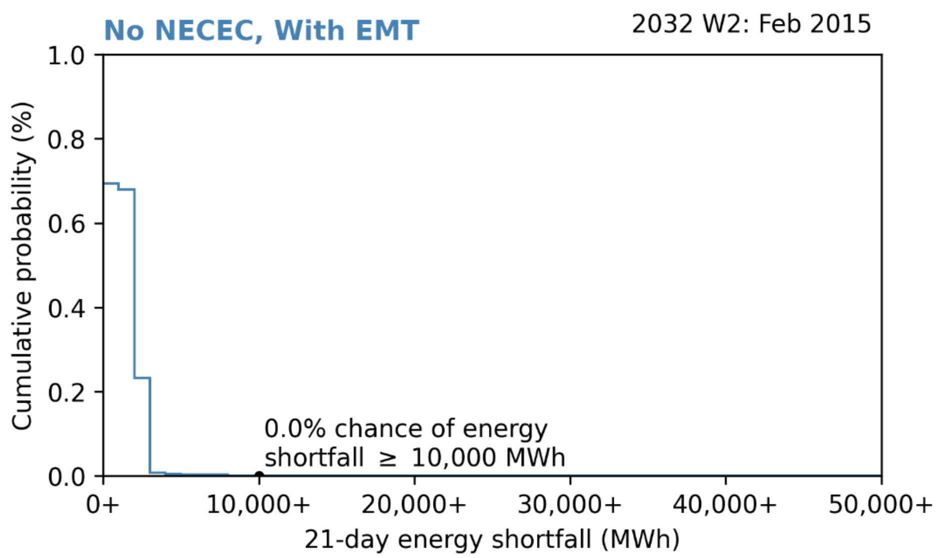
- **Min/Mean/Max (°F):** -8.1/17.1/41.9
- **Mean 100m Wind Speed (m/s):** 6.1
  - Offshore Wind avg. ~2,070 MW/hr
  - Onshore Wind avg. ~380 MW/hr
- **Mean Irradiance (W/m²):** 147.6
  - Utility Scale PV avg. ~270 MW/hr
  - BTM PV avg. ~1,395 MW/hr
- **Avg. Energy From Renewables:** ~4,115 MW/hr
- **Peak Load:** 22,361 MW (day 11)
- **Peak Daily Energy Demand:** ~435,000 MWh (day 4)
- **Total 21-Day Energy Demand:** 8.17 TWh
- **Historical Relevance:** One of Top 10 coldest 21-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: no NECEC, with EMT



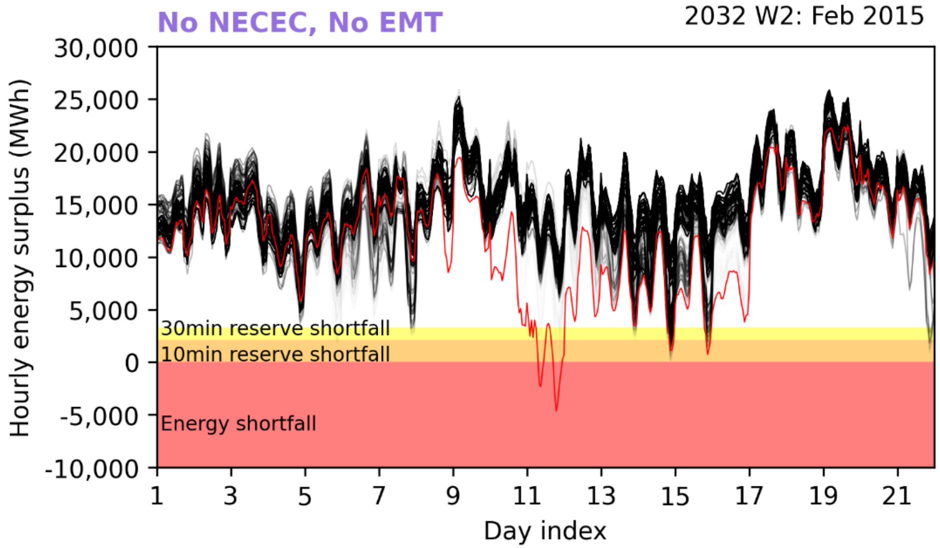


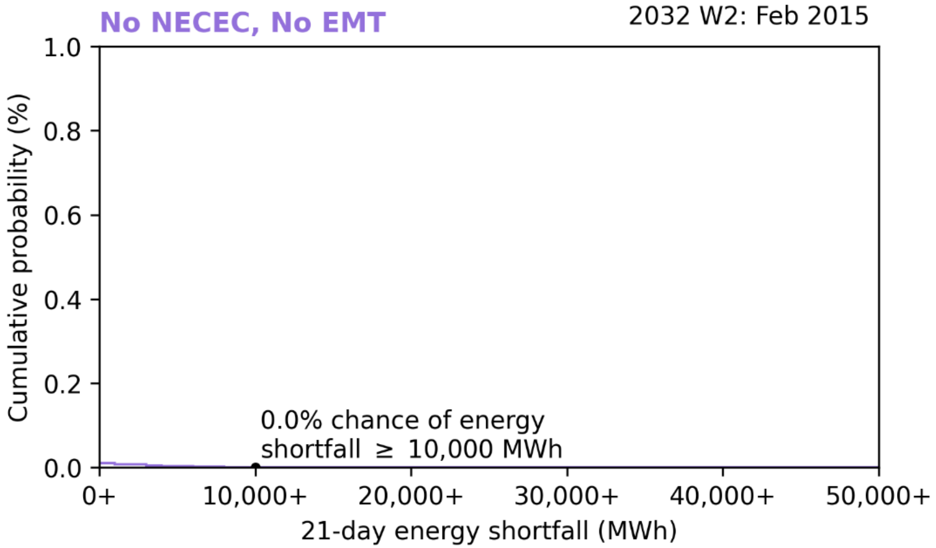
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	81	27,749	1	13	0.69%	0.000005%
2027*	33	78,148	18	7	0.47%	0.000005%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: no NECEC, no EMT



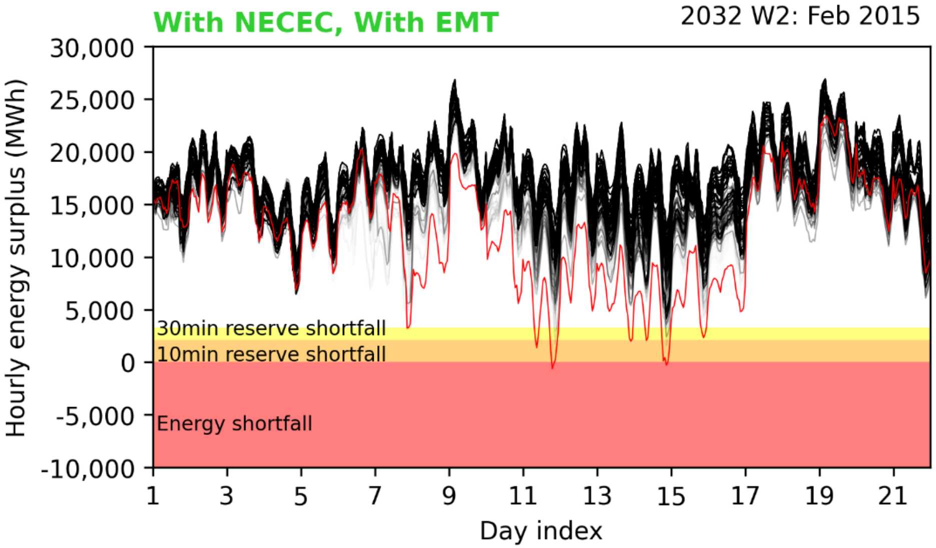


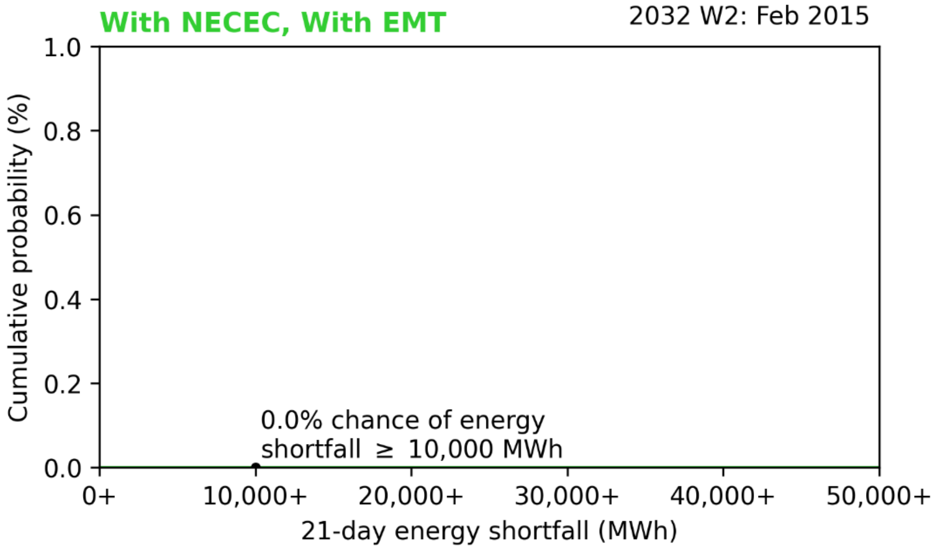
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	67	20,008	6	0	0.01%	0.000005%
2027*	18	71,255	10	1	0.02%	0.000005%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: with NECEC, with EMT



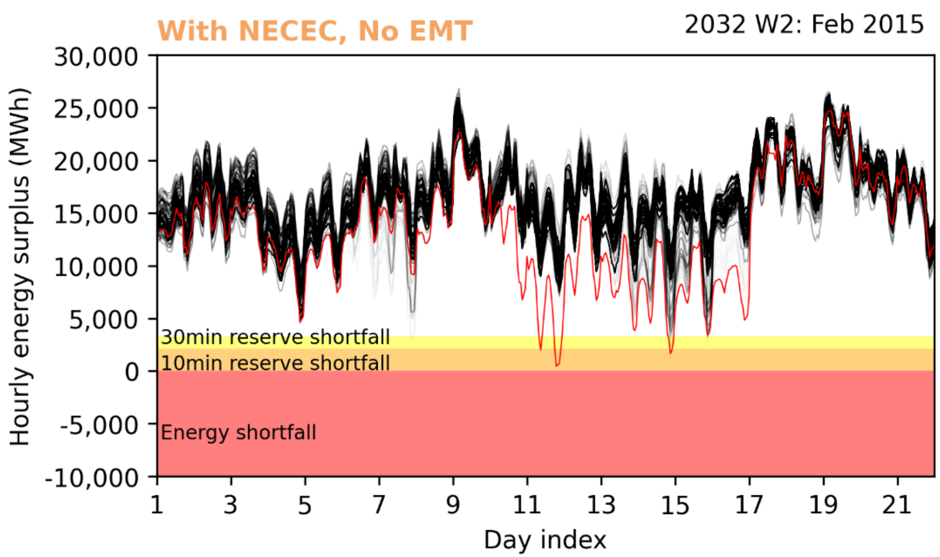


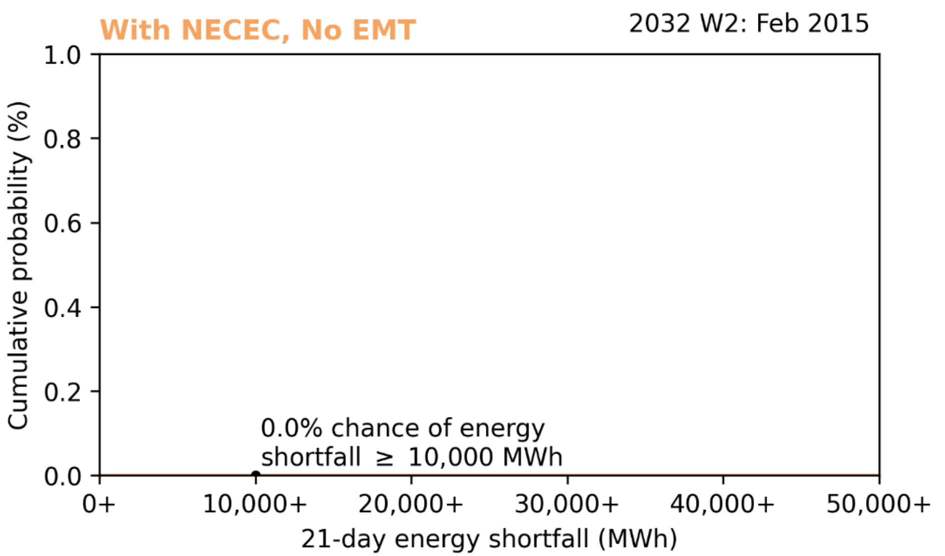
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	3	1,078	282	0	0.000016%	0.000005%
2027*	0	0	0	0	0.00%	0.0%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Summary of 21-Day Energy Analysis Results

Feb 14, 2015 Event; Scenario: with NECEC, no EMT



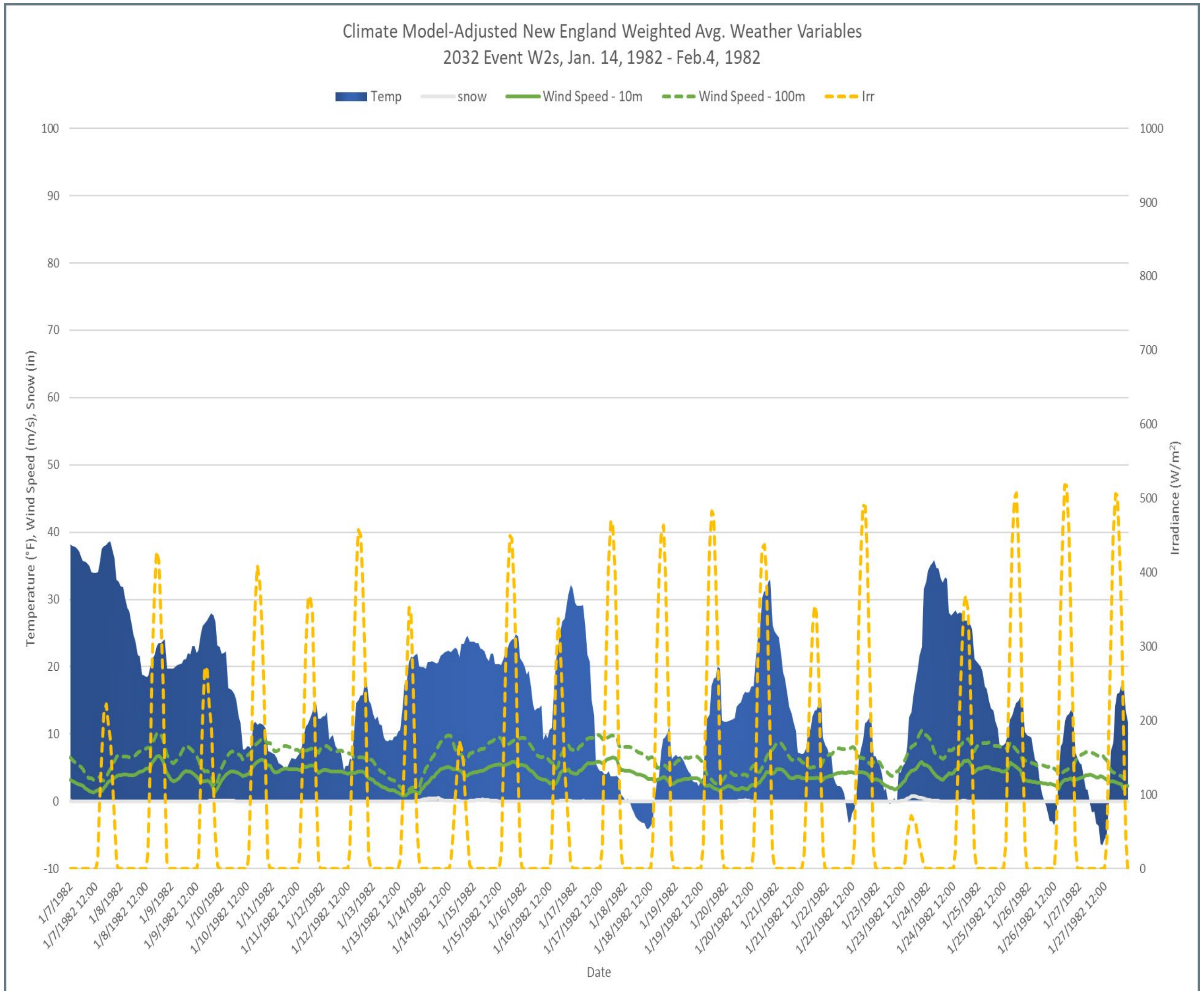


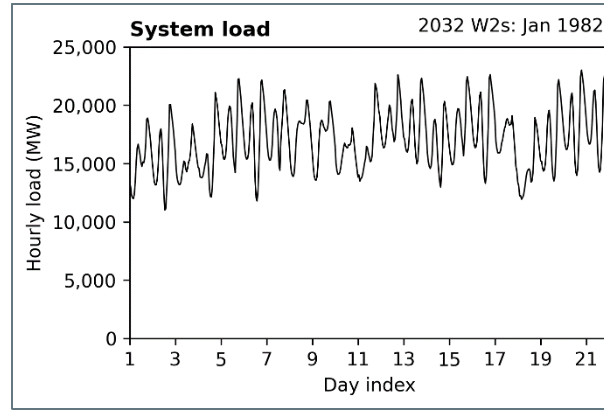
Study Year	# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
2032	0	0	0	0	0.00%	0.0%
2027*	0	0	0	0	0.00%	0.0%

*Throughout this presentation, where 21-day events have been evaluated for both study years (2027 & 2032), results from both years are provided for comparison

Jan 7, 1982 Winter Event Overview

Multiple Short-Duration Cold Waves Coincident With Low Wind and Very Low Solar



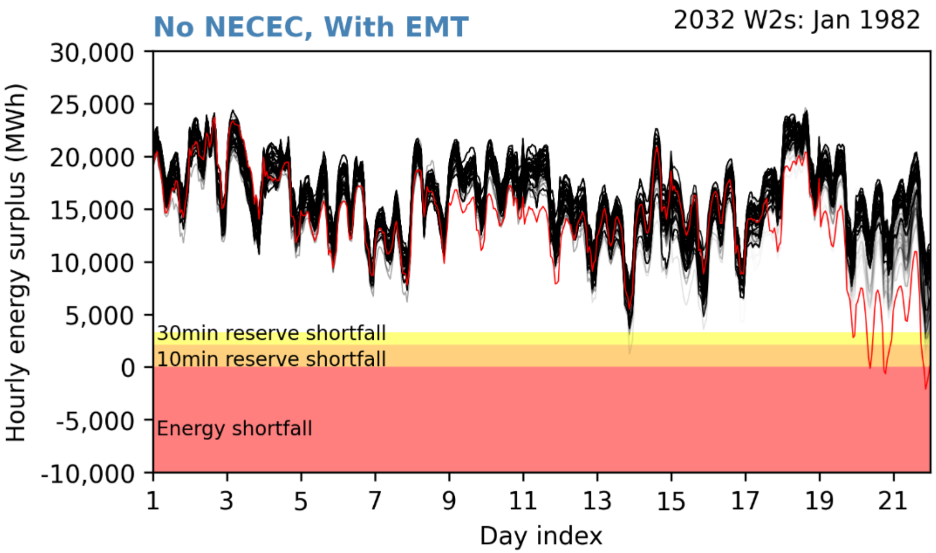


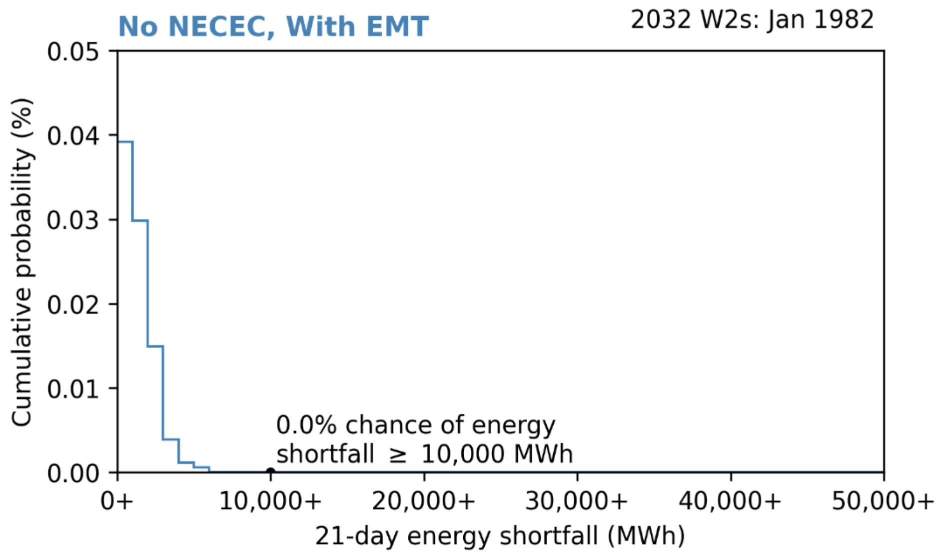
- **Min/Mean/Max (°F):** -6.5/15.0/38.6
- **Mean 100m Wind Speed (m/s):** 6.6
  - Offshore Wind avg. ~2,960MW/hr
  - Onshore Wind avg. ~450MW/hr
- **Mean Irradiance (W/m²):** 91.2
  - Utility Scale PV avg. ~160 MW/hr
  - BTM PV avg. ~920 MW/hr
- **Avg. Energy From Renewables:** ~4,490 MW/hr
- **Peak Load:** 23,554 MW (day 20)
- **Peak Daily Energy Demand:** ~445,000 MWh (day 12)
- **Total 21-Day Energy Demand:** 8.76 TWh
- **Historical Relevance:** One of Top 10 coldest 21-day periods since 1950

*temperatures, wind speeds, and irradiance are based on a New England ten-city weighted average

Summary of 21-Day Energy Analysis Results

Jan 7, 1982 Event; Scenario: no NECEC, with EMT

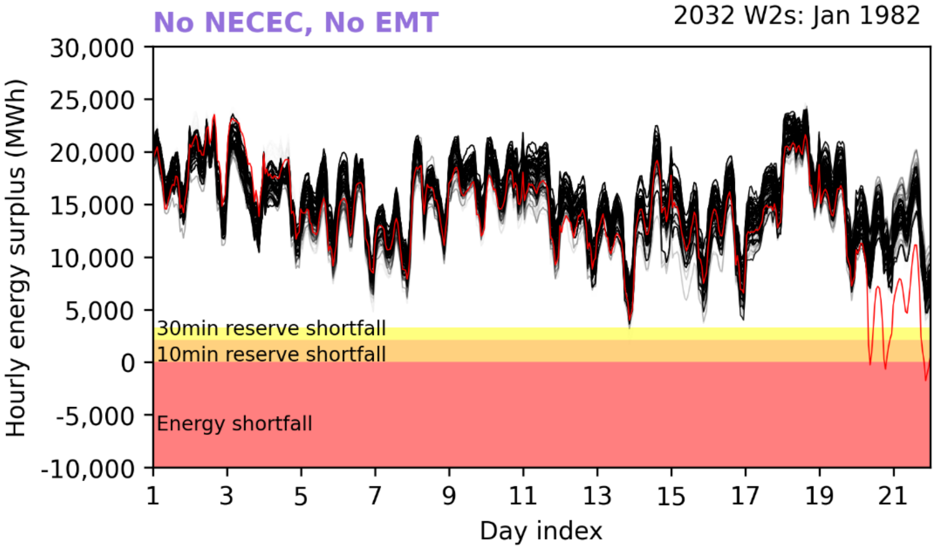


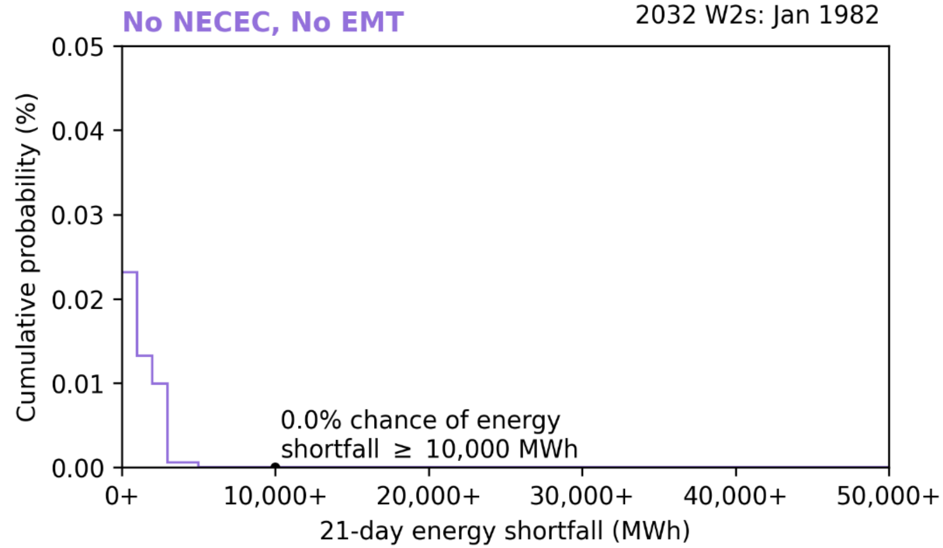


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
51	5,537	117	1	0.04%	0.00055%

Summary of 21-Day Energy Analysis Results

Jan 7, 1982 Event; Scenario: no NECEC, no EMT

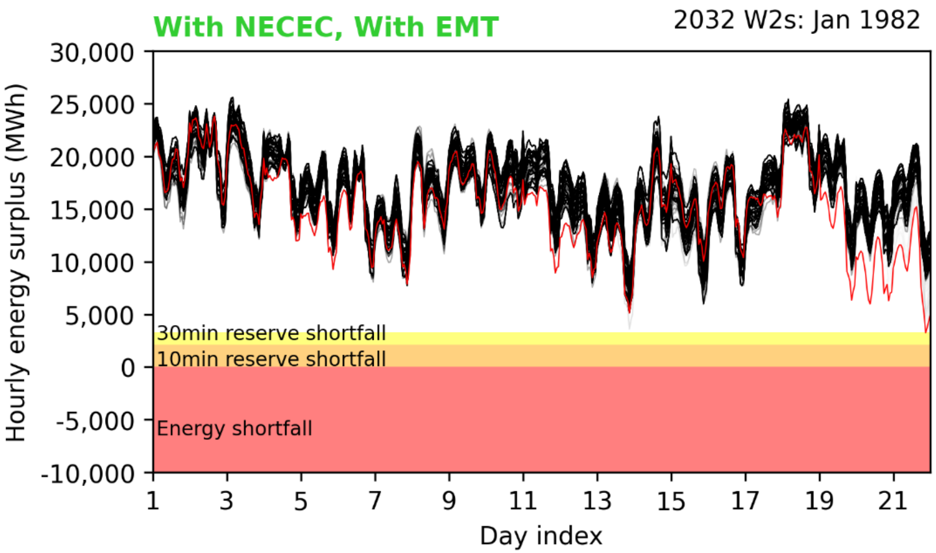


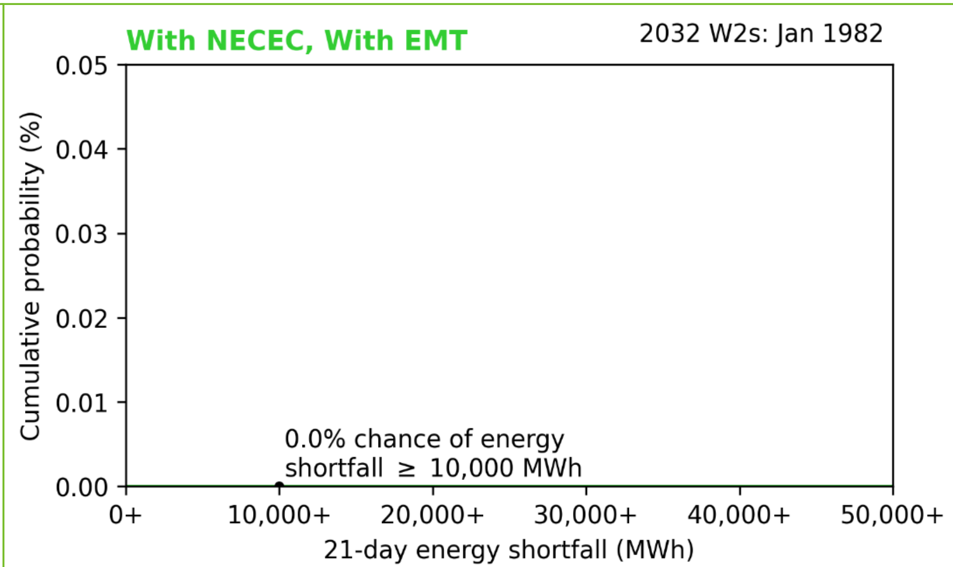


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
35	4,243	13	0	0.02%	0.00055%

Summary of 21-Day Energy Analysis Results

Jan 7, 1982 Event; Scenario: with NECEC, with EMT

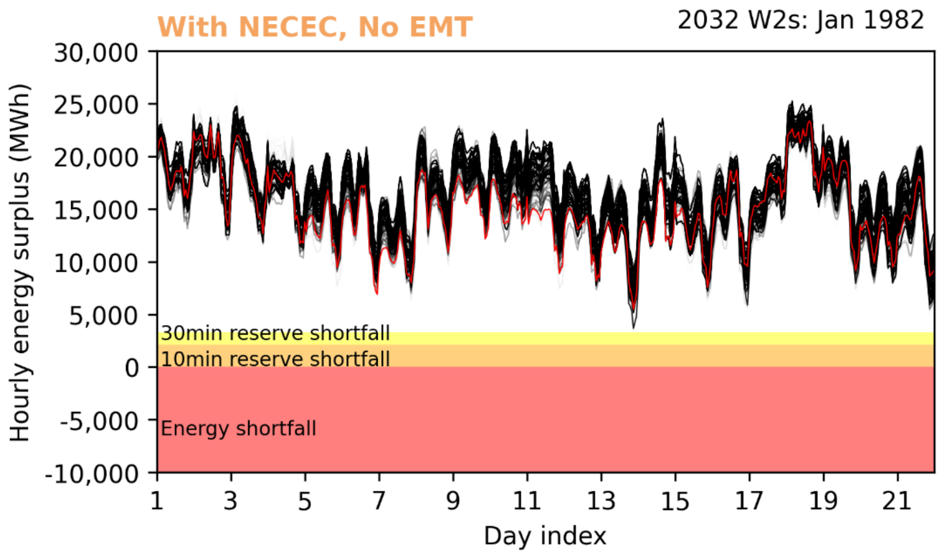


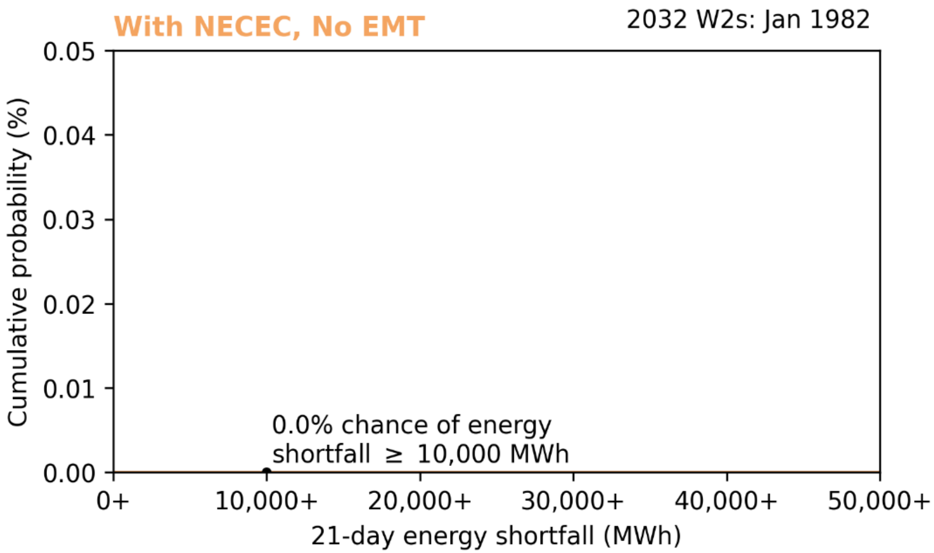


# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

Summary of 21-Day Energy Analysis Results

Jan 7, 1982 Event; Scenario: with NECEC, no EMT

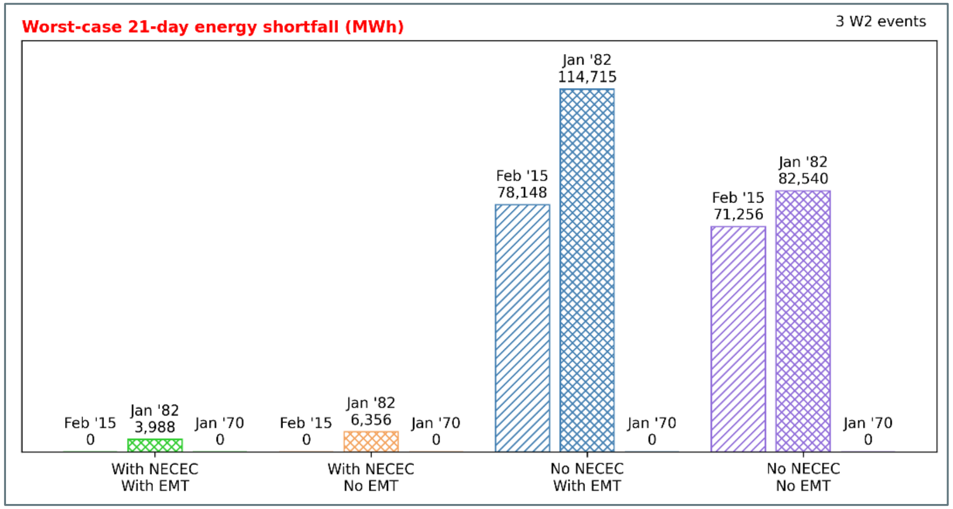




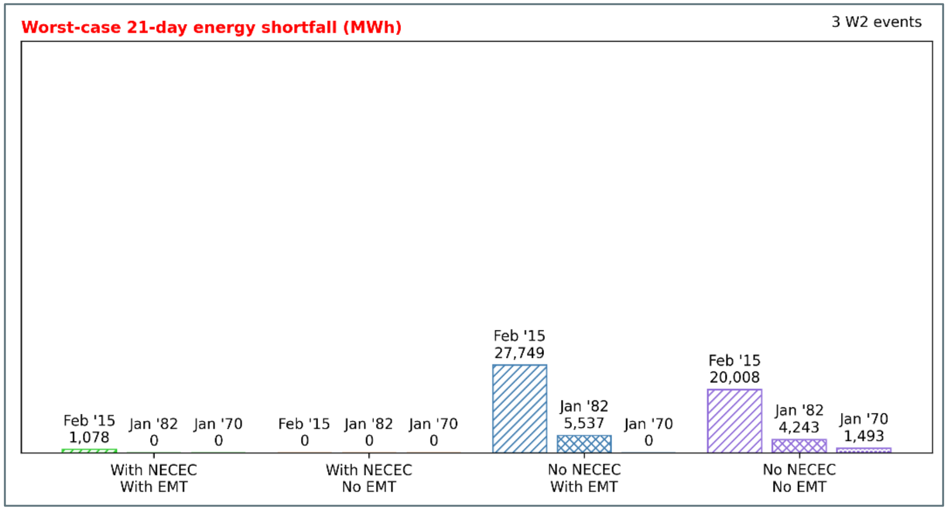
# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
0	0	0	0	0.00%	0.0%

2027 and 2032 Winter Cluster 2 Events - Comparison of Energy Shortfall Quantities

2027 Winter Cluster 2 Events



2032 Winter Cluster 2 Events



- Feb 14, 2015 and Jan 11, 1970 (medoid) events were selected for study in both 2027 and 2032
  - In 2032, Jan 7, 1982 was selected and in 2027, Jan 14, 1982 was selected
  - Results of the medoid events are included in the figures above; energy shortfall in medoid events is negligible in both study years
- Magnitude of energy adequacy risk in Winter Cluster 2 events decreases from 2027 to 2032

STEP 3: RESULTS OF SUMMER 2032 EVENTS

Summary of Results of Summer 2032 Events

- No energy shortfall was observed in any of the Summer 2032 events; only 1 hour of thirty-minute reserve shortfall was observed in one July 13, 1979 case and in one July 26, 1984 case
- Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of the Summer 2027 events
- In order to assess the impact of the higher loads associated with the 2023 CELT load forecast, ISO performed a 2023 CELT sensitivity analysis on the July 13, 1979 case
  - No energy shortfall was observed, however two hours of ten-minute reserve shortfall and five hours (up from one hour in the baseline) of thirty-minute reserve shortfall was observed

2032 WINTER EVENT SENSITIVITY ANALYSIS PERFORMED BY ISO

2032 WINTER EVENT SENSITIVITY ANALYSIS

Based on 2032 study year version of the Jan 22, 1961 event using "FCA16/CELT 2022" as baseline

Description of Sensitivity Analysis

- In order to assess energy shortfall amounts under a broad range of assumptions, ISO performed a variety of sensitivity studies based upon the 2032 study year version of the Jan 22, 1961 event
- Sensitivity studies were run on all four scenarios (all four combinations of EMT and NECEC statuses)
- Each sensitivity study uses the worst case of the Jan 22, 1961 event as a baseline; the baseline study incorporates the FCA16 resource mix and ISO's 2022 CELT heating and transportation electrification forecast
  - Based on results of 720 simulations of each scenario, the worst case results from the combination of low imports, low oil inventories, low LNG inventories, and high generator forced outage assumptions
- Building upon the baseline study, sensitivity studies incorporate variations based on three key factors:
  - FCA 17 resource mix
  - Retirement of additional at-risk resources
  - ISO's 2023 CELT heating and transportation electrification forecast
- Statistical analysis is not performed on sensitivity studies because the probability associated with each input variation is unknown

Description of Sensitivity Analysis, cont.

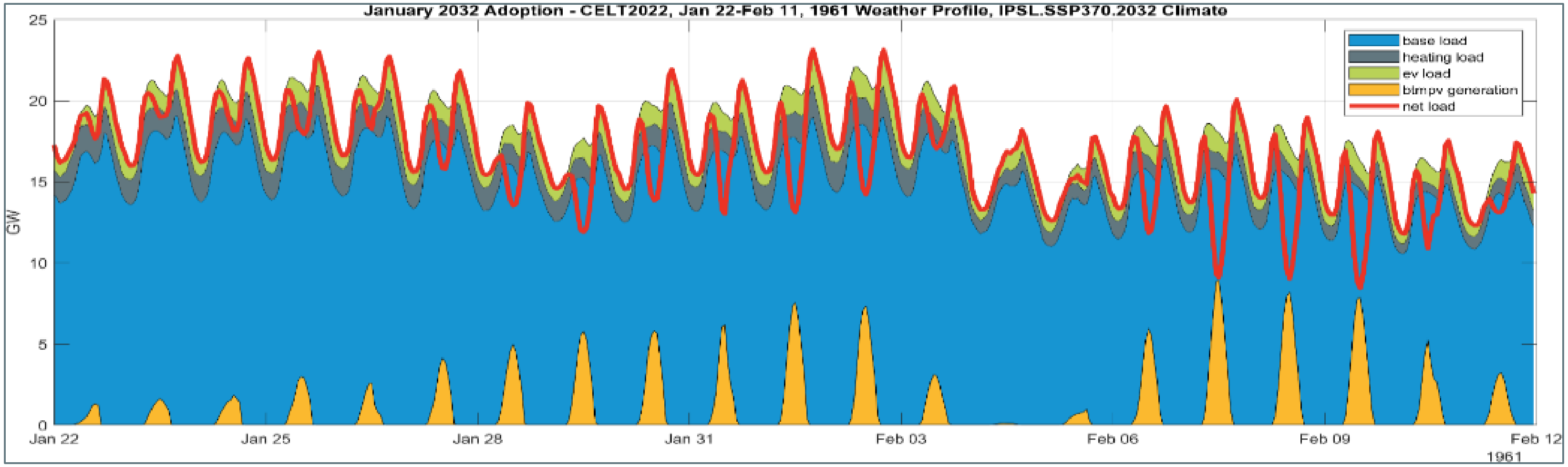
- Sensitivities that incorporate FCA 17 results assume:
  - Retirement of resources that de-listed and did not obtain a Capacity Supply Obligation in FCA 17; modelled resource retirements total ~1,600 MW of capacity
- Sensitivities that incorporate additional generator retirements (in addition to those from FCA 17) assume:
  - Retirement of an additional ~1,600 MW of Residual Fuel Oil (RFO) resources
- Retirement replacement assumptions:
  - Retired capacity of generators is replaced with new generating capacity based on a 1:1 nameplate MW ratio
  - The replacement capacity is based on the percentage of resource types currently in ISO's interconnection queue and is a blend of offshore wind (~50%), utility-scale PV (~10%), and storage battery capacity (~40%)

Description of Sensitivity Analysis, cont.

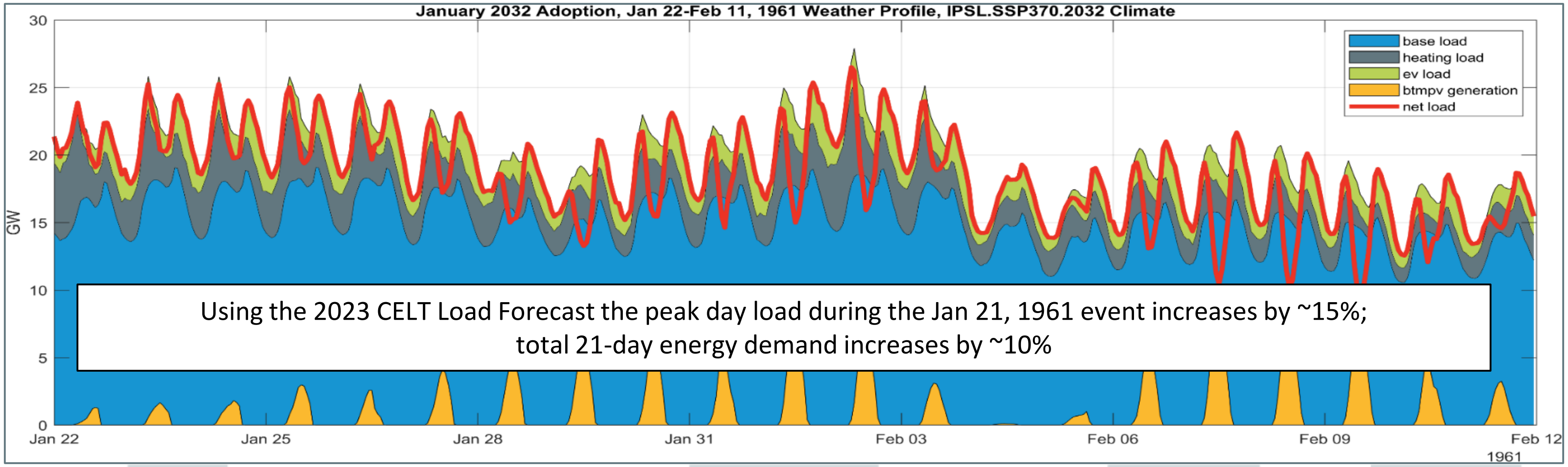
- Sensitivities that incorporate use of the 2023 CELT load forecasts include ISO's most recent heating and transportation electrification forecasts
  – The peak 21-day load for the Jan 21, 1961 event increases to 26,515 MW from 23,144 MW (+ 3,371 MW) in the 2023 CELT sensitivities; average hourly loads increase by ~1,700 MW to 18,512 MW
- Across all sensitivity cases, the replacement capacity is intended to approximately meet the installed capacity requirement (ICR)
  – The ICR value increases with the growth of load between 2027 and 2032
  – The models and inputs do not include the current Resource Capacity Accreditation design
  – The resource scenarios are approximate and do not consider the various uncertainties over the next decade
- The results of the sensitivity analysis were intended to provide a range of possible outcomes

Load Increases Significantly When 2023 CELT Electrification Load Forecast is Used

2022 CELT Load Forecast

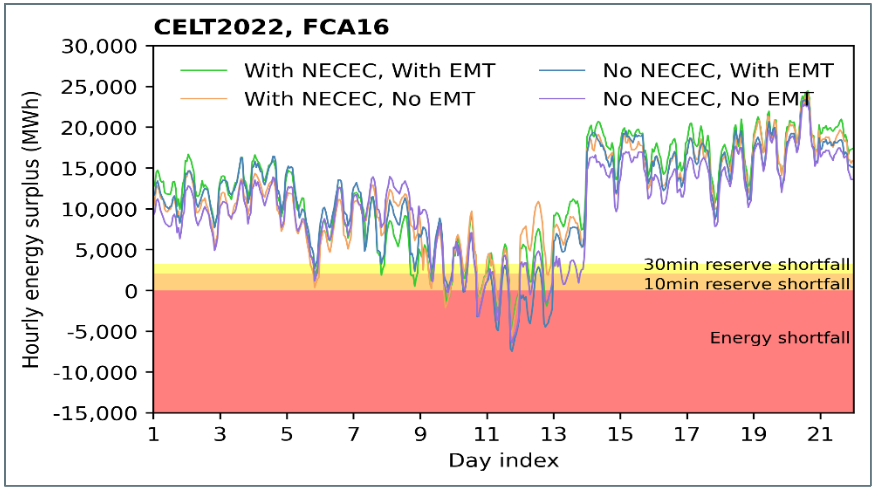


2023 CELT Load Forecast



Sensitivity Analysis Results – Jan 22, 1961 Event

FCA 16 Resource Mix and 2022 CELT



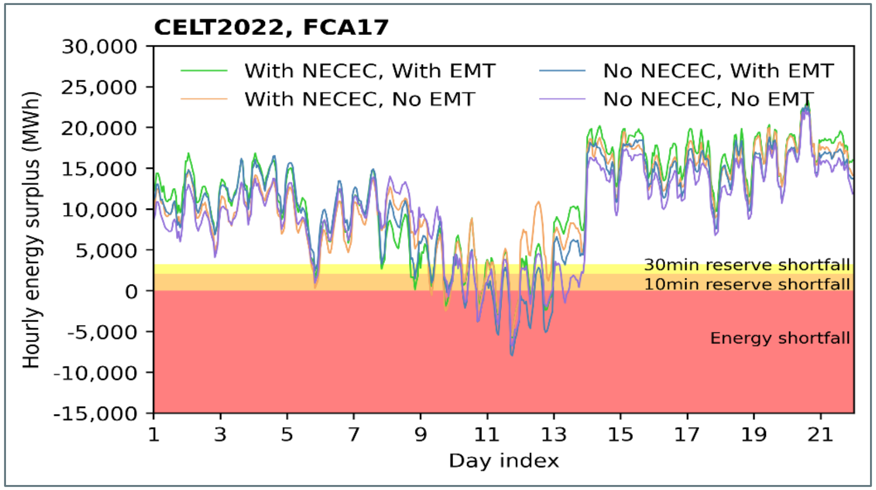
Key Assumptions	
CELT Load Forecast Year	2022
FCA Results	FCA16
Retired Capacity	2,100 MW total
Offshore Wind Capacity	4,800 MW total
Storage Battery Capacity	1,450 MW total
Utility-scale PV Capacity	1,250 MW total
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline*	68,932	53,518	111,353	95,888
2032 FCA 16/2022 CELT*	**31,974**	**33,019**	**115,642**	**63,781**

*2027 Baseline Study results are as presented in the "Step 3: 2027 Winter cluster 1 (W1) results" subsection

Sensitivity Analysis Results – Jan 22, 1961 Event

FCA 17 Resource Mix and 2022 CELT

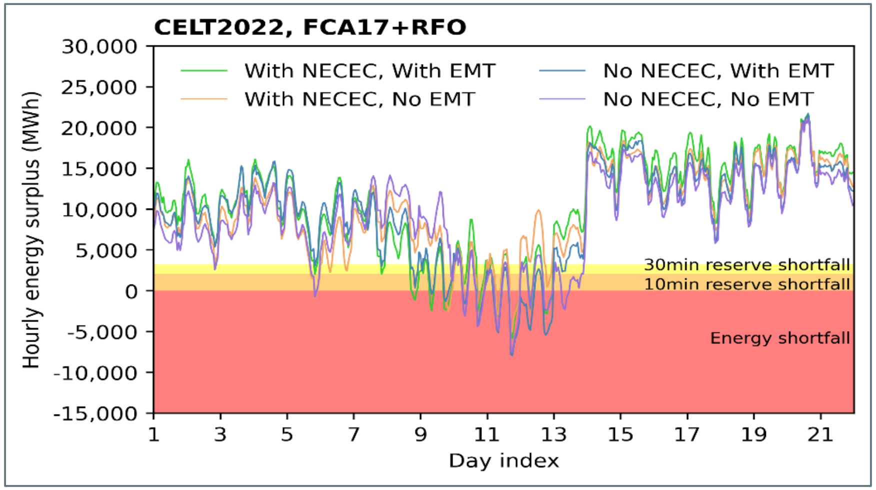


Key Assumptions	
CELT Load Forecast Year	2022
FCA Results	**FCA17**
Retired Capacity	**+1,600 MW/3,700 MW total**
Offshore Wind Capacity	**+800 MW/5,600 MW total**
Storage Battery Capacity	**+600 MW/2,050 MW total**
Utility-scale PV Capacity	**+200 MW/1,450 MW total**
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline	68,932	53,518	111,353	95,888
2032 FCA 16/2022 CELT	31,974	33,019	115,642	63,781
2032 FCA 17/2022 CELT	**49,843**	**44,095**	**134,343**	**78,772**

Sensitivity Analysis Results – Jan 22, 1961 Event

FCA 17 Resource Mix + RFO Retirement, 2022 CELT

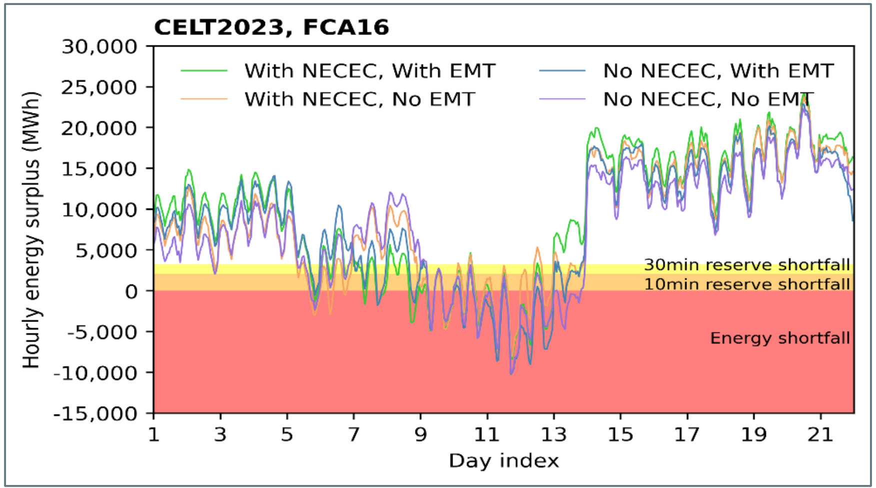


Key Assumptions	
CELT Load Forecast Year	2022
FCA Results	FCA 17
Retired Capacity	+1,600 MW/5,300 MW total
Offshore Wind Capacity	+800 MW/6,400 MW total
Storage Battery Capacity	+600 MW/2,650 MW total
Utility-scale PV Capacity	+200 MW/1,650 MW total
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline	68,932	53,518	111,353	95,888
2032 FCA 16/2022 CELT	31,974	33,019	115,642	63,781
2032 FCA 17/2022 CELT	49,843	44,095	134,343	78,772
2032 FCA 17+RFO/2022 CELT	**67,710**	**45,712**	**140,706**	**102,142**

Sensitivity Analysis Results – Jan 22, 1961 Event

FCA16 Resource Mix and 2023 CELT Load Forecast

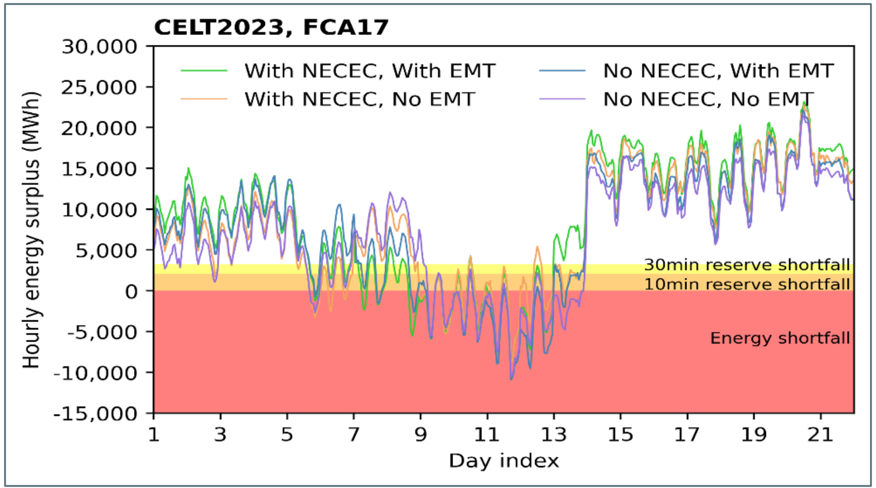


Key Assumptions	
CELT Load Forecast Year	**2023**
FCA Results	FCA 16
Retired Capacity	2,100 MW total
Offshore Wind Capacity	4,800 MW total
Storage Battery Capacity	1,450 MW total
Utility-scale PV Capacity	1,250 MW total
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline	68,932	53,518	111,353	95,888
2032 FCA 16/2022 CELT	31,974	33,019	115,642	63,781
2032 FCA 17/2022 CELT	49,843	44,095	134,343	78,772
2032 FCA 17+RFO/2022 CELT	67,710	45,712	140,706	102,142
2032 FCA 16/2023 CELT	**151,717**	**112,519**	**239,350**	**182,485**

Sensitivity Analysis Results – Jan 22, 1961 Event

FCA17 Resource Mix and 2023 CELT Load Forecast

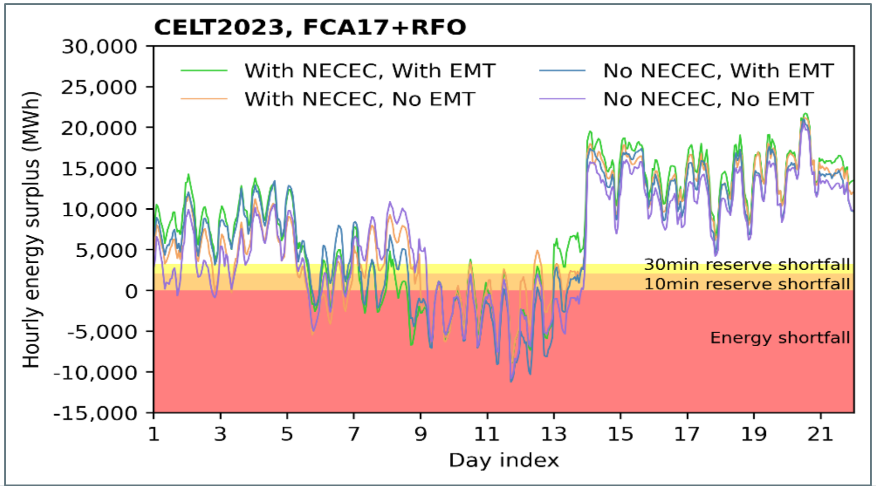


Key Assumptions	
CELT Load Forecast Year	2023
FCA Results	**FCA 17**
Retired Capacity	**+1,600 MW/3,700 MW total**
Offshore Wind Capacity	**+800 MW/5,600 MW total**
Storage Battery Capacity	**+600 MW/2,050 MW total**
Utility-scale PV Capacity	**+200 MW/1,450 MW total**
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline	68,932	53,518	111,353	95,888
2032 FCA 16/2022 CELT	31,974	33,019	115,642	63,781
2032 FCA 17/2022 CELT	49,843	44,095	134,343	78,772
2032 FCA 17+RFO/2022 CELT	67,710	45,712	140,706	102,142
2032 FCA 16/2023 CELT	151,717	112,519	239,350	182,485
2032 FCA 17/2023 CELT	**189,550**	**137,587**	**272,796**	**215,733**

Sensitivity Analysis Results – Jan 22, 1961 Event

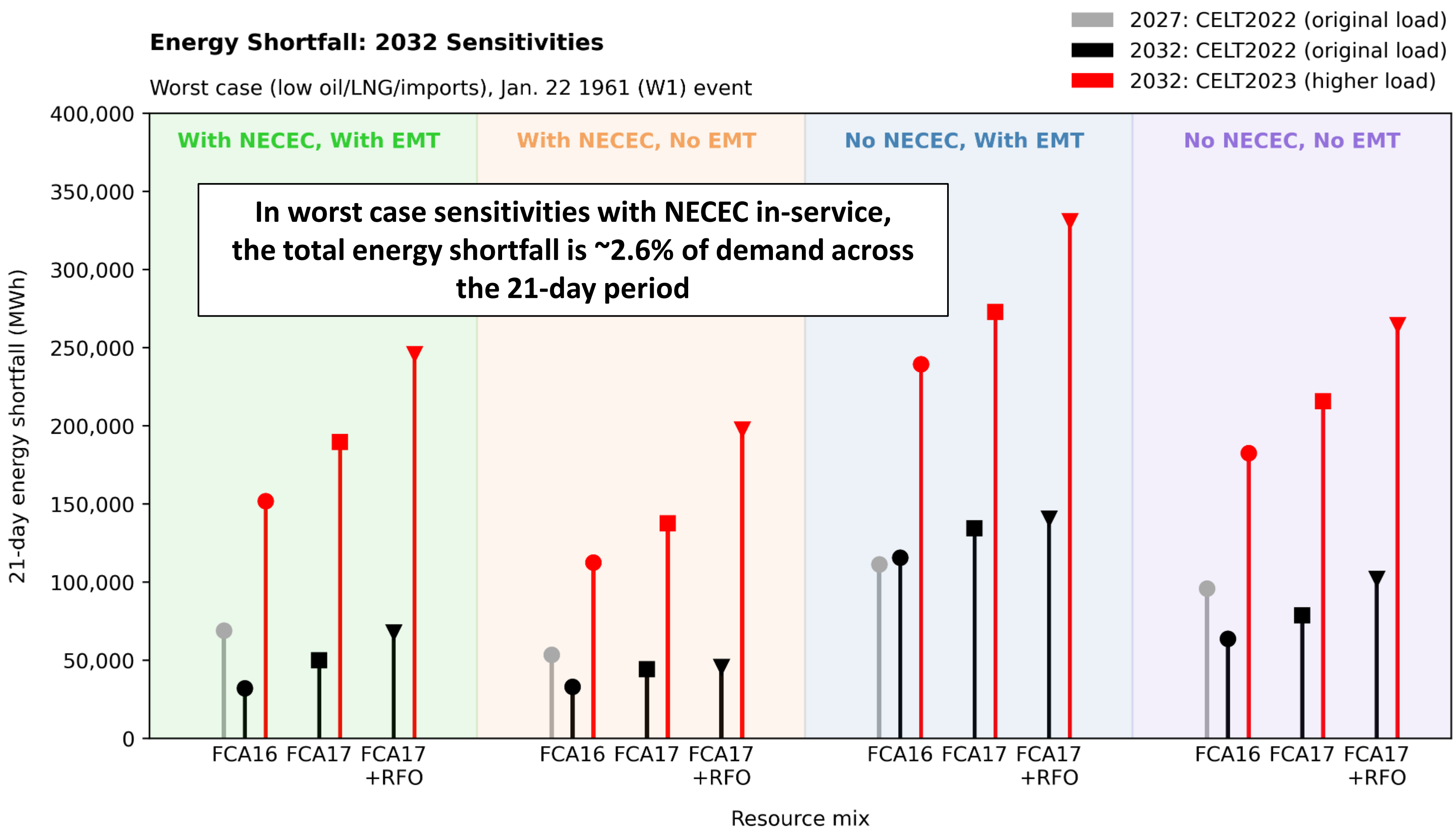
FCA17 Resource Mix + RFO Retirement, 2023 CELT Load Forecast



Key Assumptions	
CELT Load Forecast Year	2023
FCA Results	FCA17
Retired Capacity	+1,600 MW/5,300 MW total
Offshore Wind Capacity	+800 MW/6,400 MW total
Storage Battery Capacity	+600 MW/2,650 MW total
Utility-scale PV Capacity	+200 MW/1,650 MW total
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline	68,932	53,518	111,353	95,888
2032 FCA 16/2022 CELT	31,974	33,019	115,642	63,781
2032 FCA 17/2022 CELT	49,843	44,095	134,343	78,772
2032 FCA 17+RFO/2022 CELT	67,710	45,712	140,706	102,142
2032 FCA 16/2023 CELT	151,717	112,519	239,350	182,485
2032 FCA 17/2023 CELT	189,550	137,587	272,796	215,733
2032 FCA 17+RFO/2023 CELT	**245,763**	**197,520**	**330,760**	**264,356**

Results Highlight the Impact of Retirements and Electrification on Energy Shortfall Amounts



2032 WINTER EVENT STAKEHOLDER-INFORMED SENSITIVITY ANALYSIS

Based on 2032 study year version of the Jan 22, 1961 event using "FCA17/CELT 2023" as baseline

Overview of Stakeholder-Informed Sensitivity Analysis

- Recognizing interest in assumptions related to the region's resource mix and demand projections for 2032, ISO accepted stakeholder input regarding additional sensitivity analysis focused on the 2032 winter based the worst case of the Jan 22, 1961 event
  - Stakeholder sensitivity requests reflected significant interest in sensitivities related to the impacts of additional renewables and generator retirements
- ISO performed analysis of 30 unique sensitivity requests and results are summarized in the following presentation
  - ISO performed 13 additional sensitivity analyses in order to help provide additional context to some of the stakeholder sensitivity requests
- Each sensitivity is a deterministic analysis that incorporates the modification of one or more specific inputs; probabilistic data has not been generated as part of the sensitivity analysis
- Results and takeaways should be considered in the context of the specific assumptions of each case studied and the attributes of the worst case of the Jan 22, 1961 event

Overview of Stakeholder-Informed Sensitivity Analysis, cont.

- Stakeholder feedback regarding sensitivity analysis indicated a strong preference for performance of sensitivity analysis using a baseline that incorporates ISO's 2023 CELT load forecast and a resource mix aligned with ISO's FCA17 sensitivity analysis
- All sensitivity analysis was performed using ISO's Jan 22, 1961 event "2032 FCA 17/2023 CELT" sensitivity study[1] as a baseline
  - This baseline incorporates results of FCA 17 and the 2023 CELT load forecast
  - All modifications performed in order to accommodate sensitivity requests are incremental to those included in the baseline
- ISO's FCA 17 modeling includes resources that obtained a CSO in FCA 17 or were selected under state RFP's[2]; resources that de-listed in FCA 17 and did not obtain a CSO are assumed to be retired
  - Modeled retirements total ~1,600 MW of capacity[3], including 375 MW of natural gas-only, ~450 MW of coal, and ~750 MW of RFO resources; retired capacity of generators is replaced with new capacity based on a 1:1 nameplate MW ratio[4]

1: For details on ISO's "2032 FCA17/2023 CELT" sensitivity study, see slide xx of this document
2: This includes Millstone Station which is currently on a state contract
3: In addition to the ~2,100 MW of retirements from FCA 16
4: Replacement capacity is based on the percentage of resource types currently in ISO's interconnection queue; a y storage capacity (~40%)

Need final update of slide # at end of review

Overview of Stakeholder-Informed Sensitivity Analysis, cont.

- All sensitivities include the NECEC in-service; this is due to the high likelihood of NECEC being in-service by 2032
- Storage batteries are all modeled as 2-hour duration resources as this best represents existing resources; future modeling enhancements will enable the incorporation of longer-duration storage
- Nameplate capacity quantities utilized in ISO's sensitivity analysis are outlined in the table below; resource types not included in a table on the following slides that summarize results can be assumed to have the nameplate capacity shown in the table below

Sensitivity Analysis Baseline Assumptions (values are nameplate capacity, MW)

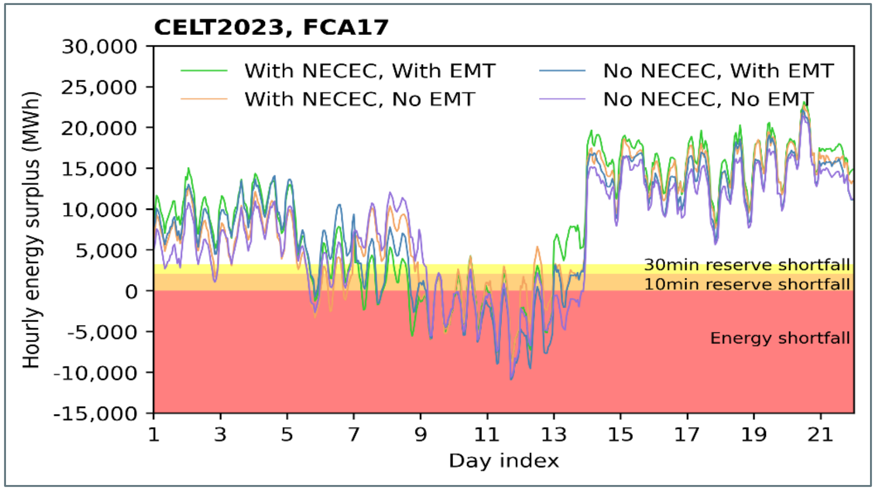
	CELT	FCA	Onshore Wind (LBW)	Offshore Wind (OFW)	Battery Storage	Utility-Scale PV	BTM PV	Demand Response (DR)	Nuclear	NG Only	Dual Fuel (DF)	RFO	DFO Only
FCA 17 Baseline	2023	FCA 17	1,500	5,600	2,050	1,450	12,000	260	3,350	8,830	7,180	3,150	1,110

REVIEW OF "2032 FCA 17/2023 CELT" SENSITIVITY STUDY RESULTS

Baseline for Stakeholder-Informed Sensitivity Analysis

Sensitivity Analysis Results – Jan 22, 1961 Event

FCA17 Resource Mix and 2023 CELT Load Forecast[1]



Sensitivity Analysis Assumptions	
CELT Load Forecast Year	2023
FCA Results	FCA 17
Retired Generating Capacity	+1,600 MW/3,700 MW total
Offshore Wind Capacity	+800 MW/5,600 MW total
Battery Storage Capacity	+600 MW/2,050 MW total
Utility-Scale PV Capacity	+200 MW/1,450 MW total
BTM PV Capacity	12,000 MW

Study Year/ Sensitivity Name	With EMT, With NECEC (energy shortfall, MWh)	No EMT, With NECEC (energy shortfall, MWh)	With EMT, No NECEC (energy shortfall, MWh)	No EMT, No NECEC (energy shortfall, MWh)
2027 Baseline	68,932	53,518	111,353	95,888
2032 FCA17/2023 CELT	**189,550**	**137,587**	**272,796**	**215,733**

- The sensitivity “2032 FCA17/2023 CELT” is referred to as “FCA 17 Baseline” on the following slides describing results of stakeholder-informed sensitivity analysis
- Total energy demand across the 21-day study period is ~ 9.3 TWh; in cases with NECEC in-service, **the total energy shortfall in this sensitivity is ~1.5 - 2.0% of the total 21-day energy demand**

1: results previously presented at the August 15, 2023 RC Meeting; see slide 44 of the “Operational Impact of Extreme Weather Events” presentation

RESULTS OF STAKEHOLDER-INFORMED SENSITIVITY ANALYSIS

Modifications of Load Profiles

Key Assumptions					Sensitivity Analysis Results	
Sensitivity	Retirement Replacement Strategy	Peak Hourly Load (MW)	Avg. Hourly Load (MW)	21-Day Energy Demand (TWh)	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	n/a	26,515	18,512	9.3	189,550	137,587
-10% Load	n/a	**23,864**	**16,661**	**8.4**	30,048 **(-84%)**	17,964 **(-87%)**
-20% Load	n/a	**21,212**	**14,810**	**7.5**	0 **(-100%)**	0 **(-100%)**
+10% Load	n/a	**29,167**	**20,363**	**10.3**	485,481 **(+156%)**	401,143 **(+192%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- Load profile sensitivities were modeled as adjustments to hourly load profiles used in the FCA 17 baseline

Modifications of Imports

Key Assumptions				Sensitivity Analysis Results	
Sensitivity[3]	Retirement Replacement Strategy	Maximum Hourly Imports (MW)	Average Hourly Imports (MW)	Energy Shortfall – With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	n/a	5,610	3,378	189,550	137,587
-20% Imports	n/a	**4,488**	**2,702**	256,726 **(+35%)**	196,478 **(+43%)**
+20% Imports[2]	n/a	**5,625**	**4,015**	132,823 **(-30%)**	94,206 **(-32%)**
+50% Imports[2]	n/a	**5,625**	**4,759**	70,904 **(-63%)**	49,037 **(-64%)**
+50% Imports, no cap[1]	n/a	**8,415**	**5,066**	64,980 **(-66%)**	46,600 **(-66%)**

In the table above, **blue rows indicate FCA 17 baseline,** **gray rows indicate stakeholder sensitivities,** **and yellow rows (if any) indicate ISO sensitivities**

- Import sensitivities were modeled as adjustments to hourly net interchange levels used in the FCA 17 baseline
- The +20% and +50% increase in imports contributes an additional ~321,000 and ~696,000 MWh, respectively, over the 21-day time period, or ~3.5 and ~7.5% of the total 21-day energy demand
- As mentioned, all sensitivities include the NECEC in-service; additional import capability would be required to accommodate transfer levels above 5,625 MW in the +50% imports, no cap sensitivity

(1) In this sensitivity, imports are not capped at maximum transfer capability of ~5,625 MW w/ NECEC in-service; additional import capability would be needed to accommodate these transfer levels
(2) In these sensitivities, imports are capped at maximum transfer capability of ~5,625 MW w/ NECEC in-service, as needed
(3) The FCA 17 Baseline sensitivity and all other sensitivities shown include the NECEC in-service

Addition of BTM PV Nameplate Capacity, No Additional Retirements

Key Assumptions (nameplate capacity values in MW)			**Sensitivity Analysis Results**	
Sensitivity	**Retirement Replacement Strategy**	**BTM PV**	**Energy Shortfall – With EMT (MWh)**	**Energy Shortfall – No EMT (MWh)**
FCA 17 Baseline	n/a	12,000	189,550	137,587
+20% BTM PV	n/a	**14,400**	170,343 **(-10%)**	127,842 **(-7%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- Additional BTM PV is incremental to ~12,000 MW of nameplate capacity modelled in ISO's 2032 studies for a total of 14,400 MW
- Incremental installation of PV resources can aid in the preservation of stored fuels during cold weather events; in this event, the additional 2.4 GW of nameplate BTM PV capacity contributes an additional ~130,000 MWh over the 21-day time period, or ~1.5% of the total 21-day energy demand; 130,000 MWh is equivalent to ~9M gallons of fuel oil

Addition of Active Demand Response Nameplate Capacity, No Additional Retirements

Key Assumptions (nameplate capacity values in MW)			**Sensitivity Analysis Results**	
Sensitivity	**Retirement Replacement Strategy**	**Active Demand Response**	**Energy Shortfall – With EMT (MWh)**	**Energy Shortfall – No EMT (MWh)**
FCA 17 Baseline	n/a	**260**	189,550	137,587
+0.5 GW DR	n/a	**760**	147,011 **(-22%)**	106,500 **(-23%)**
+1.0 GW DR	n/a	**1,260**	116,656 **(-38%)**	83,467 **(-39%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- Additional active demand response capacity is incremental to the ~300 MW of real-time demand response capacity modelled in the FCA 17 baseline
- Active demand response is the last resource type to be dispatched in ISO's 21-day energy simulator; it is modeled as a dispatchable resource with no weather dependency, which may overestimate the capacity factor of these resources

Retirements of Fossil Fuel Resources and QC-based Addition of Renewable Resources

Key Assumptions (nameplate capacity values in MW)										**Sensitivity Analysis Results**	
Sensitivity	**Retirement Replacement Strategy**	**LBW**	**OFW**	**Battery Storage**	**Utility-Scale PV**	**NG Only[3]**	**Dual Fuel[3]**	**RFO[3]**	**DFO Only[3]**	**Energy Shortfall - With EMT (MWh)**	**Energy Shortfall – No EMT (MWh)**
FCA 17 Baseline	n/a	1,500	5,600	2,050	1,450	8,830	7,180	3,150	1,110	189,550	137,587
1 GW Fossil Retirement, + OFW	1:1 QC[1,2]	1,500	**7,267**	2,050	1,450	**8,360**	**6,860**	**2,960**	**1,060**	119,492 **(-37%)**	79,813 **(-42%)**
1 GW Fossil Retirement, + LBW	1:1 QC[1,2]	**3,881**	5,600	2,050	1,450	**8,360**	**6,860**	**2,960**	**1,060**	142,006 **(-25%)**	102,572 **(-25%)**
1 GW Fossil Retirement, + Utility-Scale PV	1:1 QC[1,2]	1,500	5,600	2,050	**3,950**	**8,360**	**6,860**	**2,960**	**1,060**	181,002 **(-5%)**	133,616 **(-3%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

(1) Retirements are comprised of fossil-fuel resources based on the proportions of each type of resource available to be retired in sensitivity scenarios
(2) Qualified Capacity (QC) values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) Retirement quantities may not add exactly to 1 GW due to rounding to nearest whole unit

Retirements of Fossil Fuel Resources and QC-based Addition of Renewable Resources, cont.

Key Assumptions (nameplate capacity values in MW)										Sensitivity Analysis Results	
Sensitivity	Retirement Replacement Strategy	LBW	OFW	Battery Storage	Utility-Scale PV	NG Only[3]	Dual Fuel[3]	RFO[3]	DFO Only[3]	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	n/a	1,500	5,600	2,050	1,450	8,830	7,180	3,150	1,110	189,550	137,587
1 GW Fossil Retirement, + Battery Storage	1:1 QC[1,2]	1,500	5,600	**3,050**	1,450	**8,360**	**6,860**	**2,960**	**1,060**	210,586 **(+11%)**	163,052 **(+19%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- Retirement of a mix of fossil fuel resources accompanied by QC-based addition of onshore wind, offshore wind, and utility-scale PV has a positive impact on energy shortfall
  - 1,667 MW of additional OFW nameplate capacity results in a ~37-42% decrease, 2,381 MW of additional LBW nameplate capacity results in a ~25% decrease, and 2,500 MW of additional utility-scale PV nameplate capacity results in a 3-5% decrease
- QC-based addition of 2-hour battery storage resources results in an ~11-19% increase in energy shortfall amounts; notably ISO has not modeled the impact of longer-duration battery storage, but expects to enhance the storage modeling capability of the PEAT framework in the future

(1) Retirements are comprised of fossil-fuel resources based on the proportions of each type of resource available to be retired in sensitivity scenarios
(2) Qualified Capacity (QC) values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) Retirement quantities may not add exactly to 1 GW due to rounding to nearest whole unit

Retirement of 1.5 GW of Natural Gas-Only Resources

Key Assumptions (nameplate capacity values in MW)						Sensitivity Analysis Results	
Sensitivity	Retirement Replacement Strategy	OFW	Battery Storage	Utility-Scale PV	Natural Gas-Only	Energy Shortfall - With EMT (MWh)	Energy Shortfall - No EMT (MWh)
FCA 17 Baseline	-	5,600	2,050	1,450	8,830	189,550	137,587
1.5 GW natural gas-only retirement	None	5,600	2,050	1,450	**7,330**	192,646 **(+2%)**	137,964 *(negligible change)*
1.5 GW natural gas-only retirement	1:1 nameplate, ISO renewable mix[1]	**6,360**	**2,640**	**1,650**	**7,330**	143,426 **(-24%)**	104,449 **(-24%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- In this sensitivity, the retirement of 1.5 GW of natural gas-only resources and replacement with a mix of renewable resources results in reduced energy shortfall; this is caused by the retirement of relatively high heat-rate natural gas-fired resources that had been unavailable (i.e. not operating), at times, in the FCA 17 baseline due to a lack of gas availability
  - ISO's additional sensitivity where there is no replacement of retired resources demonstrates that it is the additional renewables that reduce the energy shortfall quantities

(1) ISO renewable mix is based on the percentage of resource types currently in ISO's interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)

Retirement of 1.6 GW of Residual Fuel Oil Resources

Key Assumptions (nameplate capacity values in MW)						**Sensitivity Analysis Results**	
Sensitivity	Retirement Replacement Strategy	OFW	Battery Storage	Utility-Scale PV	RFO	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	-	5,600	2,050	1,450	3,150	189,550	137,587
1.6 GW RFO retirement	None	5,600	2,050	1,450	**1,550**	314,229 **(+66%)**	245,429 **(+78%)**
1.6 GW RFO retirement[1]	1:1 nameplate, ISO renewable mix[2]	**6,400**	**2,650**	**1,650**	**1,550**	245,763 **(+30%)**	197,520 **(+44%)**
1.6 GW RFO retirement	1:1 QC[3], ISO renewable mix	**6,933**	**2,690**	**1,850**	**1,550**	206,878 **(+9%)**	158,834 **(+15%)**
1.6 GW RFO retirement	1:1 QC, new renewable mix[4]	**7,330**	**2,450**	**1,850**	**1,550**	177,844 **(-6%)**	140,346 **(+2%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- With the exception of the QC-based sensitivity (with EMT) that incorporates the “new renewable mix”, which includes higher penetrations of offshore wind than the “ISO renewable mix”, each 1.6 GW RFO retirement sensitivity results in increased energy shortfall

(1) This sensitivity is identical to ISO’s sensitivity analysis “2032 FCA17/2023 CELT”, as presented at the September 2023 Reliability Committee Meeting, is shared here for comparison purposes with other RFO sensitivity results
(2) ISO renewable mix is based on the percentage of resource types currently in ISO’s interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)
(3) QC values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(4) New renewable mix is based on a stakeholder sensitivity request; a blend of offshore wind (~65%), utility-scale PV (~10%), and battery storage capacity (~25%)

Retirement of all Residual Fuel Oil Resources

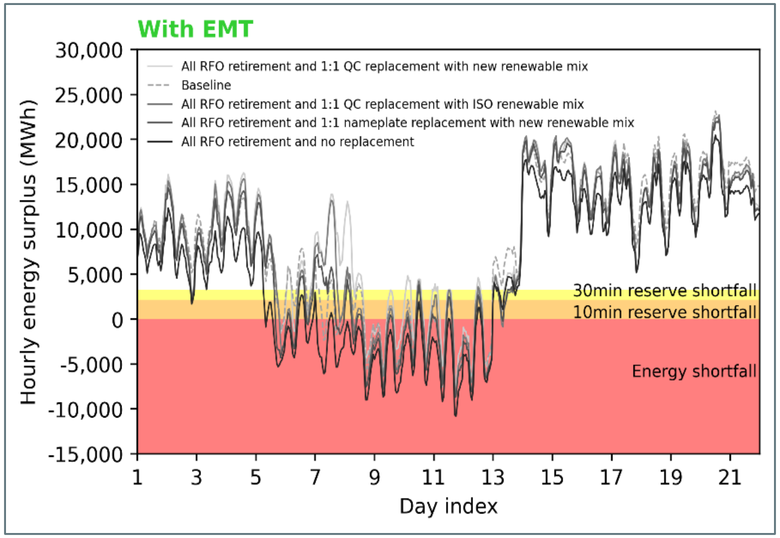
Key Assumptions (nameplate capacity values in MW)						**Sensitivity Analysis Results**	
Sensitivity	**Retirement Replacement Strategy**	**OFW**	**Battery Storage**	**Utility-Scale PV**	**RFO**	**Energy Shortfall - With EMT (MWh)**	**Energy Shortfall - No EMT (MWh)**
FCA 17 Baseline	-	5,600	2,050	1,450	3,150	189,550	137,587
All RFO retirement	None	5,600	2,050	1,450	**0**	505,381 **(+167%)**	416,237 **(+203%)**
All RFO retirement	1:1 nameplate, new renewable mix[3]	**7,680**	**2,840**	**1,760**	**0**	282,054 **(+49%)**	233,780 **(+70%)**
All RFO retirement	1:1 QC[2], ISO renewable mix[1]	**8,230**	**3,310**	**2,240**	**0**	224,846 **(+19%)**	187,295 **(+36%)**
All RFO retirement	1:1 QC, new renewable mix[3]	**9,010**	**2,840**	**2,240**	**0**	165,337 **(-13%)**	125,663 **(-9%)**

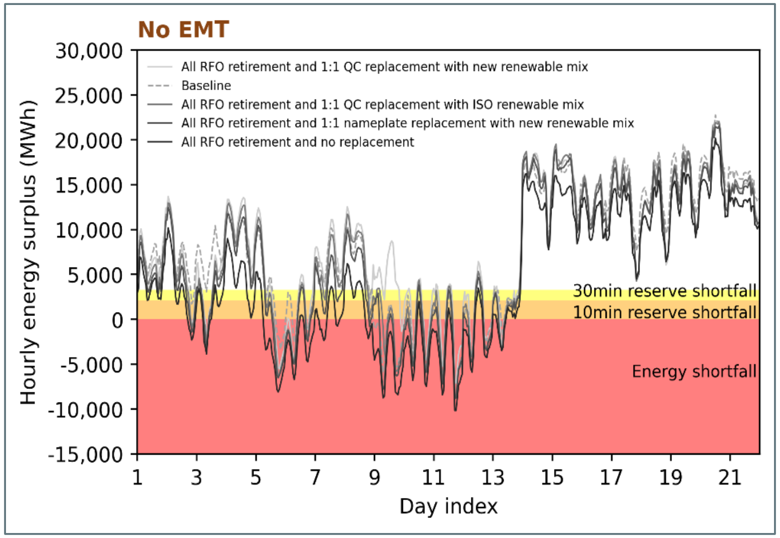
In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- With the exception of the QC-based sensitivity that incorporates the “new renewable mix”, each “all RFO retirement” sensitivity results in increased energy shortfall

(1) ISO renewable mix is based on the percentage of resource types currently in ISO’s interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)
(2) QC values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) New renewable mix is based on a stakeholder sensitivity request; a blend of offshore wind (~65%), utility-scale PV (~10%), and battery storage capacity (~25%)

Retirement of all Residual Fuel Oil Resources, cont.





- The figures above provide a visual depiction of 21-day energy shortfall quantities under the various RFO retirement sensitivities

Retirement of 1.0 GW of Nuclear Resources

Key Assumptions (nameplate capacity values in MW)						**Sensitivity Analysis Results**	
Sensitivity	Retirement Replacement Strategy	OFW	Battery Storage	Utility-Scale PV	Nuclear	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline[4]	-	5,600	2,050	1,450	3,350	189,550	137,587
1.0 GW nuclear retirement	None	5,600	2,050	1,450	**2,350**	292,555 **(+54%)**	232,275 **(+69%)**
1.0 GW nuclear retirement	1:1 nameplate, new renewable mix[3]	**6,250**	**2,300**	**1,550**	**2,350**	245,715 **(+30%)**	192,149 **(+40%)**
1.0 GW nuclear retirement	1:1 QC[2], ISO renewable mix[1]	**6,430**	**2,450**	**1,700**	**2,350**	233,012 **(+23%)**	184,164 **(+34%)**
1.0 GW nuclear retirement	1:1 QC, new renewable mix[3]	**6,680**	**2,300**	**1,700**	**2,350**	218,105 **(+15%)**	166,939 **(+21%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

(1) ISO renewable mix is based on the percentage of resource types currently in ISO's interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)
(2) QC values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) New renewable mix is based on a stakeholder sensitivity request; a blend of offshore wind (~65%), utility-scale PV (~10%), and battery storage capacity (~25%)
(4) One ~1,200 MW nuclear unit was on a forced outage in the FCA17 baseline case for 198 hours (~8.25 days)

Retirement of all Nuclear Resources

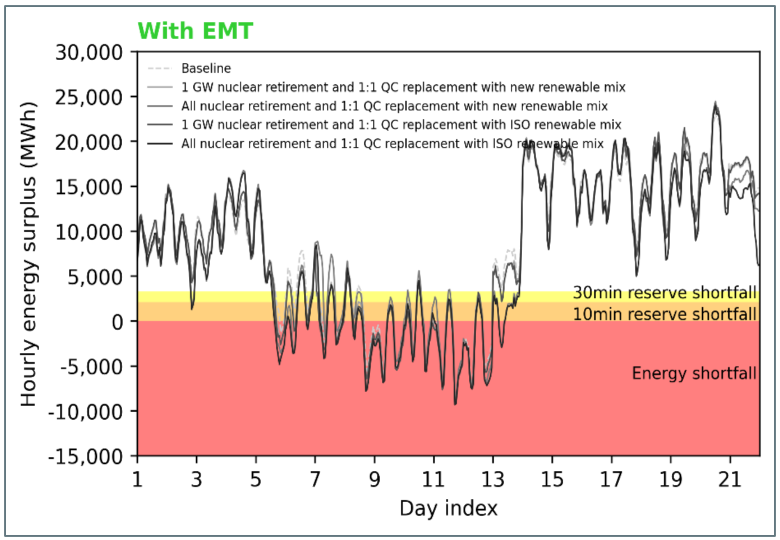
Key Assumptions (nameplate capacity values in MW)						Sensitivity Analysis Results	
Sensitivity	**Retirement Replacement Strategy**	**OFW**	**Battery Storage**	**Utility-Scale PV**	**Nuclear**	**Energy Shortfall - With EMT (MWh)**	**Energy Shortfall - No EMT (MWh)**
FCA 17 Baseline[4]	-	5,600	2,050	1,450	3,350	189,550	137,587
All nuclear retirement	None	5,600	2,050	1,450	**0**	541,769 **(+185%)**	470,487 **(+242%)**
All nuclear retirement	1:1 nameplate, new renewable mix[3]	**7,778**	**2,887**	**1,785**	**0**	341,804 **(+80%)**	294,623 **(+114%)**
All nuclear retirement	1:1 QC[2], ISO renewable mix[1]	**8,390**	**3,390**	**2,280**	**0**	285,722 **(+50%)**	241,812 **(+76%)**
All nuclear retirement	1:1 QC, new renewable mix[3]	**9,230**	**2,890**	**2,280**	**0**	231,766 **(+22%)**	185,642 **(+35%)**

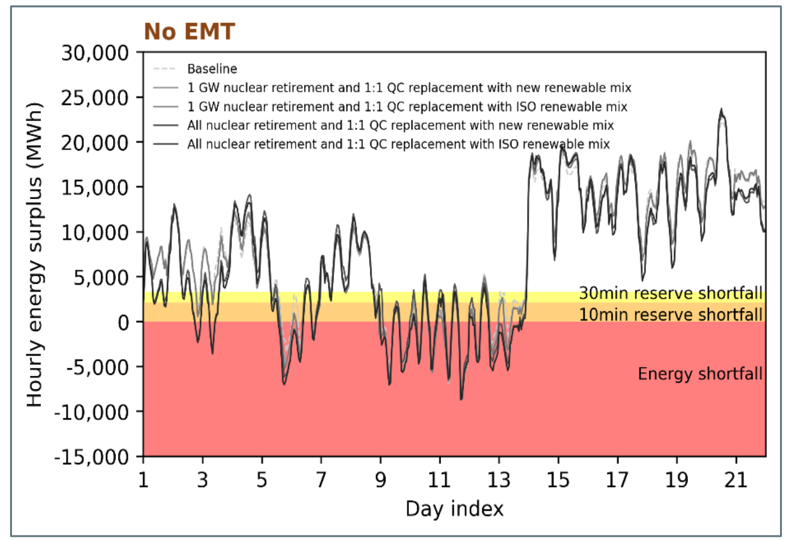
In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- Each sensitivity that considers retirement of nuclear capacity, regardless of quantity of retirements (1.0 GW or all) or retirement replacement strategy, results in increased energy shortfall; the magnitude of energy shortfall in the all nuclear retirement/no replacement sensitivity is ~5.1-5.8% of 21-day total energy demand

(1) ISO renewable mix is based on the percentage of resource types currently in ISO's interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)
(2) QC values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) New renewable mix is based on a stakeholder sensitivity request; a blend of offshore wind (~65%), utility-scale PV (~10%), and battery storage capacity (~25%)
(4) One ~1,200 MW nuclear unit was on a forced outage in the FCA17 baseline case for 198 hours (~8.25 days)

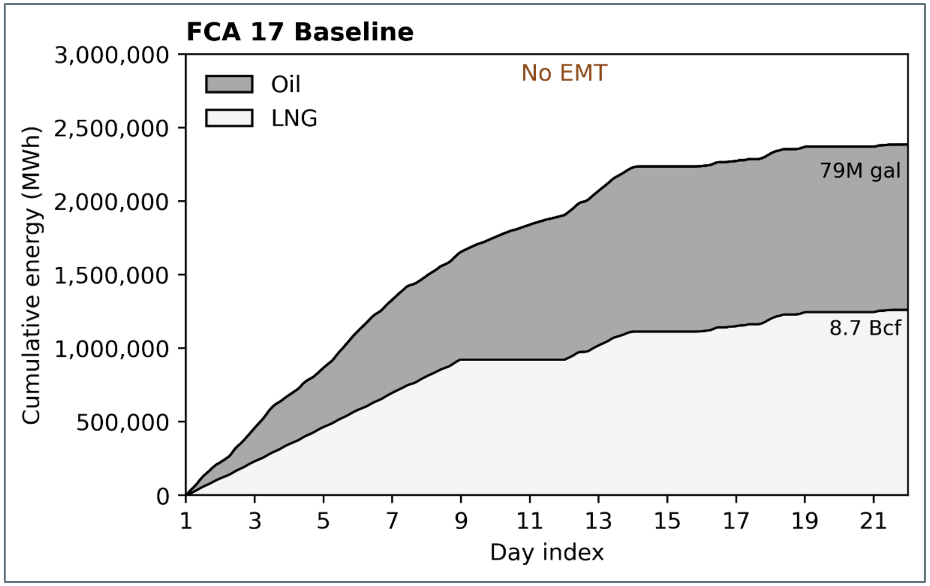
Retirement of all Nuclear Resources, cont.

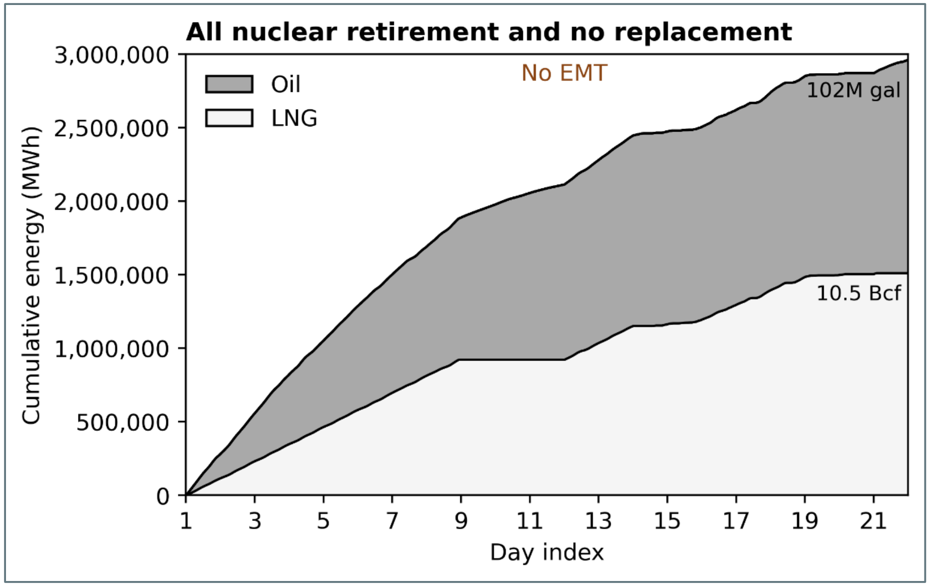




- The figures above provide a visual depiction of 21-day energy shortfall quantities under the various all nuclear retirement sensitivities

Energy From Stored Fuels Increases ~25% in the All Nuclear Retirement/No Replacement Sensitivity





- In the all nuclear retirement/no replacement sensitivity, energy from stored fuels serves ~32% of the 21-day total energy demand
- Increases in cumulative energy from stored fuels are similar in sensitivities with and without EMT
- Relative to the FCA 17 baseline sensitivity, fuel oil usage increases ~29% (including an additional 9M gallons of replenishment) in the all nuclear/no replacement sensitivity

Cap Offshore Wind at 1.6 GW Nameplate Capacity

Key Assumptions (nameplate capacity values in MW)			**Sensitivity Analysis Results**	
Sensitivity	Retirement Replacement Strategy	OFW	Energy Shortfall – With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	-	5,600	189,550	137,587
Cap OFW at 1.6 GW	n/a	**1,600**	502,043 **(+165%)**	403,435 **(+193%)**
In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities				

- In terms of magnitude of energy shortfall, this sensitivity is similar to the all nuclear retirement/no replacement and the all RFO retirement/no replacement sensitivities

Cap OFW at 1.6 GW Nameplate Capacity and Retirement of All Nuclear Resources

Key Assumptions (nameplate capacity values in MW)				**Results of Sensitivity Analysis**	
Sensitivity	Retirement Replacement Strategy	OFW	Nuclear	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline[1]	-	5,600	3,350	189,550	137,587
Cap OFW at 1.6 GW & Retirement of all nuclear	None	1,600	**0**	1,009,279 **(+432%)**	903,760 **(+557%)**
In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities					

- This sensitivity conveys the impact to energy shortfall amounts due to significant nuclear capacity retirement and delayed buildout of offshore wind with no additional capacity added to the system
- The retirement of all 3.35 GW of existing nuclear capacity and the capping of offshore wind at 1.6 GW of nameplate capacity would result in ~29.0 GW of capacity to serve a ~32.6 GW ICR[2] in 2032; this level of capacity would likely lead to year-round concerns with meeting system load and reserve requirements

(1) One ~1,200 MW nuclear unit was on a forced outage in the FCA17 baseline case for 198 hours (~8.25 days)
(2) Representative net ICR for 2032 based on Net Installed Capacity Requirements (ICRs), Representative Net ICRs, and Operable Capacity (Op Cap) Analysis, presented at the PAC on June 15, 2023

Reduction of Renewable Nameplate Capacity

Key Assumptions (nameplate capacity values in MW)					**Results of Sensitivity Analysis**	
Sensitivity	Retirement Replacement Strategy	OFW	Battery Storage	Utility-Scale PV	Energy Shortfall – With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	-	5,600	2,050	1,450	189,550	137,587
25% Reduction of OFW, Battery, Utility-Scale PV	n/a	**4,210**	**1,550**	**1,090**	277,590 **(+46%)**	220,853 **(+61%)**
In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities						

Reduction of Renewable Nameplate Capacity & 1.6 GW Retirement of RFO Resources

Key Assumptions (nameplate capacity values in MW)						**Results of Sensitivity Analysis**	
Sensitivity	**Retirement Replacement Strategy**	**OFW**	**Battery Storage**	**Utility-Scale PV**	**RFO**	**Energy Shortfall - With EMT (MWh)**	**Energy Shortfall – No EMT (MWh)**
FCA 17 Baseline	-	5,600	2,050	1,450	3,150	189,550	137,587
25% reduction of OFW, Battery, Utility-Scale PV & 1.6 GW RFO retirement	1:1 nameplate, ISO renewable mix[1]	**5,000**	**2,138**	**1,288**	**1,550**	371,438 **(+96%)**	287,580 **(+109%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- In this sensitivity the 25% reduction in renewables is taken from the nameplate capacities used in the FCA 17 baseline sensitivity and then replacements due to RFO retirements are added back in to the total nameplate capacities

(1) ISO renewable mix is based on the percentage of resource types currently in ISO's interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)

Modification of Fuel Oil Inventories

Key Assumptions (nameplate capacity values in MW)							**Results of Sensitivity Analysis**	
Sensitivity	Retirement Replacement Strategy	Dual Fuel Nameplate Capacity	DFO Only Nameplate Capacity	RFO Capacity	DFO Inventory (gallons)	RFO Inventory (gallons)	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	-	7,180	1,110	3,150	31.5 M	55.1 M	189,550	137,587
Fill DFO tanks	n/a	7,180	1,110	3,150	**79.8 M**	55.1 M	88,608 **(-53%)**	66,870 **(-51%)**
Fill DFO tanks and retire all RFO	n/a	7,180	1,110	**0**	**79.8 M**	**0**	295,215 **(+56%)**	232,362 **(+69%)**
In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities								

- Filling the DFO fleet's fuel oil storage tanks (an additional ~48 M gallons) at the start of the event reduces overall energy shortfall by ~50%, however given the increase in energy shortfall when all RFO capacity is retired (and not replaced), full DFO tanks do not appear to be adequate replacements for the capacity from RFO units

Modification of LNG Inventories and Replenishment in "No EMT" cases only

Key Assumptions (nameplate capacity values in MW)								**Results of Sensitivity Analysis**
Sensitivity	Retirement Replacement Strategy	OFW	Battery Storage	Utility-Scale PV	RFO	Starting LNG Inventory (Bcf)	LNG Replenish-ment (Bcf)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	-	5,600	2,050	1,450	3,150	6.5	4.1	137,587
30% reduction of starting LNG inventory and replenishment	n/a	5,600	2,050	1,450	3,150	**4.55**	**2.87**	236,301 **(+72%)**
30% reduction of starting LNG inventory and replenishment & 1.6 GW RFO retirement	1:1 nameplate, ISO renewable mix[1]	**6,400**	**2,650**	**1,650**	**1,550**	4.55	2.87	331,408 **(+141%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- As expected, energy shortfall risk is sensitive to starting LNG inventories and shortfall amounts increase with lower LNG starting inventories; the magnitude of energy shortfall increase is consistent with observations from similar sensitivities previously run and shared with stakeholders (e.g. 3 Bcf lower starting inventory sensitivity, shared in May as part of the winter 2027 preliminary study results, *see* slide no. 25)
- In this event, the reduction of replenishment quantities by 30% does not impact energy shortfall due to the timing of replenishment
- ISO continues to expect that the reduced LNG injection capability modelled in the "no EMT" scenario would be able to be made up by the other LNG facilities in the region and/or by additional fuel oil burn

(1) ISO renewable mix is based on the percentage of resource types currently in ISO's interconnection queue; a blend of offshore wind (~50%), utility-scale PV (~10%), and battery storage capacity (~40%)

Addition of Renewable Resources and Imports, with Corresponding Retirements of Fossil Fuels

Key Assumptions (nameplate capacity values in MW)												Results of Sensitivity Analysis	
Sensitivity	Retirement Replacement Strategy	LBW	OFW	Battery Storage	Utility-Scale PV	NG Only[3]	Dual Fuel[3]	RFO[3]	DFO Only[3]	Max Hourly Imports (MW)	Avg. Hourly Imports (MW)	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA 17 Baseline	n/a	1,500	5,600	2,050	1,450	8,830	7,180	3,150	1,110	5,610	3,378	189,550	137,587
Additional imports and additional renewables	1:1 QC[1,2]	**2,450**	**7,000**	**4,000**	**1,650**	**7,430**	**5,980**	**2,670**	**920**	**6,810**	**4,578**	37,960 **(-80%)**	12,866 **(-91%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- This sensitivity examines the impact of ~4.5 GW of additional nameplate capacity from renewables and a corresponding retirement of fossil fuel resources, and an additional 1,200 MW/hr of imports
  - The addition of 1,200 MW/hr of imports represents a ~36% increase in average hourly imports, or an additional ~605,000 MWh of energy which is ~6.5% of the total 21-day energy demand
  - In this sensitivity there is no cap placed on the maximum levels of imports; based on the ~5,625 MW of import transfer capability available with NECEC in-service, additional transfer capability would be needed to accommodate transfer levels in some hours

(1) Retirements are comprised of fossil-fuel resources based on the proportions of each type of resource available to be retired in sensitivity scenarios
(2) QC values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) Retirement quantities may not add exactly to 1 GW due to rounding to nearest whole unit

Pathways Study: Addition of Renewable Resources with Corresponding Retirements of Fossil Fuel

Key Assumptions (nameplate capacity values in MW)										Results of Sensitivity Analysis	
Sensitivity	Retirement Replacement Strategy	LBW	OFW	Battery Storage	Utility-Scale PV	NG Only[3]	Dual Fuel[3]	RFO[3]	DFO Only[3]	Energy Shortfall - With EMT (MWh)	Energy Shortfall – No EMT (MWh)
FCA17 Baseline	n/a	1,500	5,600	2,050	1,450	8,830	7,180	3,150	1,110	189,550	137,587
Pathways Study	1:1 QC[1,2]	**2,465**	**8,841**	**4,251**	**4,602**	**6,282**	**5,132**	**2,231**	**791**	25,774 **(-86%)**	23,117 **(-83%)**

In the table above, blue rows indicate FCA 17 baseline, gray rows indicate stakeholder sensitivities, and yellow rows (if any) indicate ISO sensitivities

- This sensitivity request, modeled after renewable resource capacity from the Pathways Study, Status Quo Policy, examines the impact of ~9.5 GW of additional nameplate capacity from renewables and retirement of ~5.8 GW of fossil fuel resources
  - In addition to the 1,465 MW of onshore wind included in the Pathways Study, Status Quo Policy, 1,000 MW more onshore wind nameplate capacity has been added per the sensitivity request for a total of 2,465 MW of onshore wind

(1) Retirements are comprised of fossil-fuel resources based on the proportions of each type of resource available to be retired in sensitivity scenarios
(2) QC values used in these sensitivities: onshore wind, offshore wind, and utility-scale PV, QC values are 42%, 60%, and 40%, respectively (values are consistent with FGRS study)
(3) Retirement quantities may not add exactly to 1 GW due to rounding to nearest whole unit

KEY TAKEAWAYS OF 2027 AND 2032 EVENTS STUDIES AND SENSITIVITY ANALYSIS

Key Takeaways of 2027 and 2032 Studies

- The region's energy shortfall risk is dynamic and will be a function of the evolution of the supply and demand profiles
  - Various assumptions inform the analysis and significant deviation from any of these assumptions may result in an increasingly risky profile
  - Assumptions include that the market will respond with new renewables to meet the increased demand caused by electrification and that transmission will be built to interconnect offshore wind resources and increase import capabilities from Canada
  - The studies also anticipate a reliable gas system, a responsive oil supply chain, and no significant disruptions in energy production due to emissions limitations
- Results of the energy adequacy studies reveal a range of energy shortfall risk and associated probabilities
  - In the near-term, the winter energy shortfall risk appears manageable over a 21-day period
  - Results are consistent with expectations for load growth and significant quantities of solar, offshore wind, battery storage resources, and additional imports

Key Takeaways of 2027 and 2032 Studies, cont.

- Sensitivity analysis of 2032 worst-case scenarios indicates an increasing energy shortfall risk profile between 2027 and 2032
  - This increasing risk profile is particularly observable with the 2023 CELT load forecast
  - Timely additions of BTM and utility-scale solar, offshore wind, and incremental imports from NECEC are critical to mitigate energy shortfall risks that result from significant winter load growth and retirements
- Results reveal similar energy adequacy risk with and without EMT in-service
  - Increases in fuel oil and coal burn are notable in cases without EMT in-service
  - The ISO has previously stated the qualitative factors that may warrant the need for EMT in the mid-term
- Assessment of summer events reveals no energy shortfall risk
  - As the supply and demand profiles evolve ISO expects to continue monitoring for changes in summer energy shortfall risk
- The PEAT framework provides a much needed foundation to study energy shortfall risk as the system evolves

Summary of Stakeholder Meetings

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee February 15, 2022	Initial presentation
Reliability Committee March 15, 2022	Summary of EPRI's historical weather analysis deliverables and discussion of macro assumptions
Reliability Committee May 17, 2022	Share results of Step 1 (Extreme Weather Modeling) report. Review and discuss Step 2 (Risk Model Development and Scenario Generation) activities
Reliability Committee July 19, 2022	Review progress on Step 2 activities
Reliability Committee September 20, 2022	Continue to gather feedback with respect to Step 2 activities
Reliability Committee November 16, 2022	Continue to gather feedback with respect to Step 2 activities
Reliability Committee January 18, 2023	Discuss preliminary results of Step 2 Risk Screening Model
Reliability Committee February 14, 2023	Continued discussion of Step 2 Risk Screening Model results

Summary of Stakeholder Meetings, cont.

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee March 14, 2023	Review outage draw and categorical branching methodologies (including LNG, fuel inventory, imports, etc.)
Reliability Committee April 18, 2023	Review 21-day energy assessment simulator, review return period methodology, and follow-up on stakeholder questions regarding modeling
Reliability Committee May 16, 2023	Review Step 3 winter 2027 preliminary results
Reliability Committee July 18-19, 2023	Review Step 3 summer 2027 preliminary results, address stakeholder feedback, outline plan for accepting stakeholder input to additional studies
Reliability Committee August 15, 2023	Review Step 3 winter 2032 preliminary results
Reliability Committee September 19, 2023	Review Step 3 summer 2032 preliminary results and review stakeholder sensitivity requests selected for analysis
Reliability Committee November 14, 2023	Review results of stakeholder-informed sensitivity analyses