ELECTRIC POWER & DEMAND RESPONSE IN NEW ENGLAND
AGENDA

• New England Overview
• Electricity Market Trends/Challenges
• Demand Management Basics
• New England Demand Response Opportunities
• Questions
WHO IS CPower?

CPower is an energy management company. We create optimized energy management strategies that help businesses streamline their energy usage, offset costs and reach sustainability goals.

- 125+ dedicated resources
- National experience. Local expertise.
- 3,500 MWs enrolled
- 15+ utility programs
- 1,500+ customers
- Focused on Demand Response
- End-to-end, full service operations and fulfillment
- Strategic partnerships with leading energy efficiency companies
NEW ENGLAND ELECTRICITY USE

FACTS

• 7.1 million retail customers
• 128,000 gigawatt hours (GWh) consumed in 2016
• Summer peak 28,130 MW (2006)
• Winter peak 22,818 MW (2004)

FORECAST

• Usage expected to decline .2% over next decade --- 125,200 GWH in 2025
• Peak Demand expected to rise .2% to 27,122 MW in 2025
• Peak demand in extreme summer weather (extended heat wave in mid 90’s) can push peak to 29,781 MW (205)

Without demand reducing impact of EE and PV, 2025 would show a usage would be 152,700 GWh and the system peak would be 34,450 MW
ISO NEW ENGLAND

Independent, not for profit, FERC authorized entity to ensure the constant availability of competitively priced wholesale electricity for the 6 state region

ROLES

• **GRID OPERATION:** Coordinate and direct flow of electricity over the region’s high voltage transmission system.

• **MARKET ADMINISTRATION:** Design run and over see the wholesale electricity market

• **POWER SYSTEM PLANNING:** Studies, Analysis and planning to ensure the region’s electricity needs are met 10 years forward
GOOD NEWS

• Natural gas and renewables resources are displacing less economic, less clean resources.
• Natural gas generating plants have increased ability to quickly balance generation output as intermittent resources production varies constantly.
• Regional air emissions are down. In the 15 years ended 2014, NOX fell 66%, SO2 94% and CO2 26%.
• Wholesale electric costs are being driven down---unless natural gas spikes.
• Distributed generation helping to offset local distribution constraints.
• Smart grid technology and rate design changes are empowering end users to use electricity more efficiently.
CHALLENGES

• Inadequate natural gas pipeline infrastructure- creating reliability concerns and higher winter air emissions

• Substantial retirements of non-gas generating plants, limiting options for reliable grid operation in constrained gas deliver environment

• Intermittent renewable resources and increase in DG adds to complexity of daily grid operations

• Expensive transmission infrastructure is needed to connect more wind and hydro resources
RESOURCES LEAVING THE GRID

- 4200MW of generation have either already exited or will close by 2019
- 6000MW of oil and coal fired generation will over 40 years old by 2020
RESOURCES ENTERING

- 15000MW of new generation and demand side assets in place. 11500MW proposed
- State RPS are promoting strong development of renewable energy resources.
- Demand resources (load management, EE, DG) have increased from 100MW in 2003 to 2500MW in 2016. Estimates are that $1.1bil will be spent annually in EE programs from 2020-2025
ISO-NE SYSTEM FUEL MIX

Percent of Total System Capacity by Fuel Type

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<tr>
<th></th>
<th>2000</th>
<th>2016</th>
<th>2024*</th>
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<tbody>
<tr>
<td>Nuclear</td>
<td>18%</td>
<td>13%</td>
<td>11%</td>
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<tr>
<td>Oil</td>
<td>34%</td>
<td>22%</td>
<td>16%</td>
</tr>
<tr>
<td>Coal</td>
<td>12%</td>
<td>6%</td>
<td>2%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>18%</td>
<td>44%</td>
<td>57%</td>
</tr>
<tr>
<td>Hydro**</td>
<td>14%</td>
<td>11%</td>
<td>9%</td>
</tr>
<tr>
<td>Renewables***</td>
<td>5%</td>
<td>4%</td>
<td>5%</td>
</tr>
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</table>

*Projected resources in 2024 assume new resources proposed in the ISO Queue and non-price retirement requests for coal, oil, and nuclear resources as of mid-2015.

**Includes pondage, run-of-river, and pumped storage.

*** Fuels include: landfill gas, methane, refuse, solar, steam, wind, and wood. Hydro is not included primarily because the various sources that make up hydroelectric generation are not universally defined as renewable in the six New England states.
PROPOSED NEW RESOURCES

By Type

- 57% Natural gas* (6,483 MW)
- 35% Wind (4,025 MW)
- 5% Solar (597 MW)
- 1% Biomass (115 MW)
- 1% Battery storage (94 MW)
- 1% Pumped-storage hydro (56 MW)
- <1% Hydro (37 MW)
- <1% Landfill gas (2 MW)

* Some natural gas projects include dual-fuel units (oil).

By State

- 20% Massachusetts (2,257 MW)
- 12% Rhode Island (1,350 MW)
- 35% Maine (3,961 MW)
- 3% New Hampshire (301 MW)
- 31% Connecticut (3,497 MW)
- <1% Vermont (52 MW)

Source: ISO Generator Interconnection Queue (August 2016)
FERC Jurisdictional Proposals Only
NATURAL GAS CONSTRAINTS

- Natural gas represents 44% of the region’s generating capacity.
- Pipeline constraints affect emissions during the winter as higher emitting generators must run due to gas not being available.
- Addressing pipeline constraints is the region’s highest priority.
ISO-NE MARKETS

• 400 buyers and sellers in the wholesale electricity marketplace
• $7.2 billion traded in wholesale electricity market in 2015; $5.9 billion in energy markets and $1.3 billion in capacity and ancillary services markets
• 75% of real time pricing set by marginal natural gas fired generators in 2015.
• Wide swings in prices underscores the continuing risk of price volatility to due to gas infrastructure constraints. The winter of 2012-13 showed high volatility and the market increased 54% in 2013. Increased gas demand and increased LNG price led to another high period of volatility in February 2015.
• The forward capacity market typically make up 15-25% of the wholesale market costs.
• The last four auctions have attracted 3000MW of new generation as well as demand resources and imports.
• Clearing prices in recent capacity auctions are higher, reflecting the need for new resources to ensure reliable supply.
ISO-NE GENERATION MIX

Cumulative New Generating Capacity in New England

Note: New generating capacity for years 2016–2019 includes resources clearing in recent Forward Capacity Auctions.
ELECTRICITY SUPPLY COST

CAPACITY
Determined by prices set from independent system operator (ISO)-run auctions and customer capacity tag (peak usage). Designed to provide grid reliability and ensure enough generation available to the region.

RENEWABLE PORTFOLIO STANDARDS (RPS)
Mandates set by individual states for load-serving entities to purchase a certain amount of renewable energy. Determined by state regulated compliance percentages and the financial market for renewable energy certificates (RECs).

ANCILLARIES
Small administrative charges billed to load-serving entities by the ISO to operate grid safely and reliably.

LINE LOSSES
Included to make up for the energy lost over transmission and distribution (T&D) lines due to heating.

ENERGY
The cost of procuring the actual electrons transmitted through the T&D lines. Largely determined by cost of natural gas for New England.
MAINTAINING THE BALANCE

Supply

Grid Operators

NEW GENERATION

LOAD REDUCTION

Demand
WHAT IS DEMAND RESPONSE?

DEMAND RESPONSE
Is most simply described as the “response” of curtailing energy usage at the times when the demand for energy is outpacing the supply.

DR is collaboration of options providing financial opportunities for electricity users to appropriately manage down total energy spend by incorporating avoided cost or offset strategies.

THERE ARE 3 OPTIONS WHEN DEMAND IS OUTPACING SUPPLY:
• Do nothing – obviously, not the best choice
• Increase supply – expensive to operators and consumers
• Decrease demand – inexpensive and effective

Collectively, the DR actions reduce the overall load on the grid during an “event”
WHAT OPPORTUNITIES DO POWER USERS HAVE?

**Permanent**
- Energy Efficiency
- Distributed Generation
- Load Shifting

**Responsive**
- Capacity
- Ancillary
- Economic
- Distribution Utility

![Graphs showing energy savings and incentives for permanent reduction in load compared to payments made for responses to peak energy curtailment.](image)
MAXIMIZING THE VALUE OF DR REVENUES
IF YOU ARE, “ALREADY DOING DR”, ARE YOU FULLY MAXIMIZING YOUR DR OPPORTUNITIES?

Establish an energy strategy that layers appropriate demand response and permanent load reduction programs available in your local market. Many programs work together, increasing the benefit of implementing a single curtailment strategy.

$ Economic  +  $ Ancillary  +  $ Peak Load Mgmt.  +  $ Utility Programs  +  $ Renewables  +  =  $

Bedrock: Participate in most suitable program
Expand program participation as experience and opportunities grow
Enhance active demand response programs with permanent strategies
Strategically apply actions and knowledge nationally
BACK TO BASICS: CURTAILMENT OPTIONS

PRIMARY ENERGY RESOURCES USED IN DR

- Lighting Reduction
- HVAC Strategy
- Generation
- Process / Production

ENERGY MANAGEMENT STRATEGIES THROUGH DEMAND RESPONSE

- Manual or Automatic Load Drop
- Energy Management Systems
- Load Shedding Strategies
- Lighting Control Strategies
- Backup Generation
- Energy Storage Systems
DEMAND RESPONSE IMPLEMENTATION PROCESS

1. Pre-qualification, documentation, contracting
2. Site audit, develop the curtailment plan
3. Meter installation
4. Confirm curtailment measures
5. Enrollment
6. Activation
7. Settlement

FULLY INTEGRATED TEAM:
A fully integrated CSP should manage the entire process of DR enrollment and fulfillment.

CONTINUOUS OPTIMIZATION:
DR is an evolutionary process. It is important that a CSP regularly reviews market changes and opportunities and works with a business to understand their operations and needs as they change over time.
NEW ENGLAND PROGRAM EDUCATION

1. Northwest Vermont
2. Vermont
3. New Hampshire
4. Seacoast
5. Maine
6. Bangor Hydro
7. Portland ME
8. Western MA
9. Springfield MA
10. Central MA
11. North Shore
12. Boston
13. SEMA
14. Lower SEMA
15. Norwalk-Stamford
16. Western CT
17. Northern CT
18. Eastern CT
19. Rhode Island
# New England Demand Response Options

<table>
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<tr>
<th>Program Name</th>
<th>Program Type</th>
<th>Customer Obligation Hours</th>
<th>Notification Lead Time</th>
<th>Program Term</th>
<th>Performance Season</th>
<th>Typical Event Length</th>
<th>Typical Curtailment Frequency</th>
<th>Administrator</th>
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<tbody>
<tr>
<td><strong>Real-Time Demand Resources</strong></td>
<td>Capacity</td>
<td>24/7/365</td>
<td>30 minutes</td>
<td>June - May</td>
<td>Summer (June-Aug) &amp; Winter (Dec-Jan)</td>
<td>3.5 Hours</td>
<td>2 x 1 Hour Mandatory Tests</td>
<td>ISO-NE</td>
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<tr>
<td><strong>On Peak Hours Resources</strong></td>
<td>Energy Efficiency Projects; &quot;Dist. Gen&quot;: On-site DG, cog, gen, solar, fuel cell</td>
<td>Summer 1pm-5pm, Winter 5pm-7pm</td>
<td>NA</td>
<td>June - May</td>
<td>Summer (June-Aug) &amp; Winter (Dec-Jan)</td>
<td>NA</td>
<td>None</td>
<td>ISO-NE</td>
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<td><strong>Transitional Price Responsive Demand</strong></td>
<td>Economic</td>
<td>Based on Customer’s Offer and Market Clearance</td>
<td>Day Ahead</td>
<td>Per Customer’s Offer</td>
<td>Per Customer’s Offer, Per Clearance of Customer’s Offer</td>
<td>Per Clearance of Customer’s Offer</td>
<td>Per Clearance of Customer’s Offer</td>
<td>ISO-NE</td>
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<td><strong>Connected Solutions</strong></td>
<td>Capacity</td>
<td>June - September 11 am – 5pm</td>
<td>Day Ahead</td>
<td>Summer 2017 &amp; Summer 2018</td>
<td>Summer Only June-Sept</td>
<td>TBD</td>
<td>20 hour Curtailment minimum</td>
<td>NGRID</td>
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<td><strong>Peak Demand Management (CAP TAG)</strong></td>
<td>Energy Bill Cost Avoidance</td>
<td>Voluntary</td>
<td>Day Ahead &amp; Day Of</td>
<td>June – May</td>
<td>Summer</td>
<td>3 hours</td>
<td>2-7 calls per year</td>
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REAL-TIME DEMAND RESPONSE

THERE ARE 2 PARTICIPATION SEASONS

Summer Season: April - November
Winter Season: December - March

IN EACH SEASON, TESTS WILL OCCUR AND EVENTS MAY OCCUR.

Test: 1 hour minimum
Actual event: Duration based on need

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<td>2011</td>
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<tr>
<td>2016</td>
<td>1</td>
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<tr>
<td>AVG.</td>
<td>1.0</td>
<td>3:44</td>
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PERFORMANCE ON UTILITY METER

PERFORMANCE IS DETERMINED AS THE AVERAGE HOURLY DIFFERENCE BETWEEN BASELINE AND ACTUAL LOAD.

Performance is determined by real time load data from installed metering equipment.
EXAMPLE: ABC INC.

**FACILITY SPECS:**

- Manufacturing facility in Boston area
- 500 DC Solar Array
- 1 MW Peak Demand
- Fixed Price Power Bill with capacity passed through
- 400 KW of curtailment flexibility (HVAC, 1 of 3 production lines, non-essential equipment)

**PROGRAMS ENROLLED:**

- ISO-NE—RTDR
- NGRID—Connected Solutions
- ISO-NE—On-Peak Program (solar)
- Peak Demand (Cap Tag) Management
ABC INC. — JULY 2017

ESTIMATED EARNINGS AND SAVINGS

RTDR – (including winter audit)
• Year 1 - $33,744
• Year 2 - $45,840

Connected Solutions – (assuming June, Aug, Sept calls as well)
• Year 1 - $14,000
• Year 2 - $14,000

On-Peak Program – (Solar, non-dispatchable)
• Year 1 - $14,060
• Year 2 - $19,100

Peak Demand Management (Cap tag)
• Year 2 savings - $41,840
• Year 3 savings - $29,744

Offset Revenues [$140,744] + Capacity Savings [$71,584] = 2 Year Total Energy Benefit = $212,328
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