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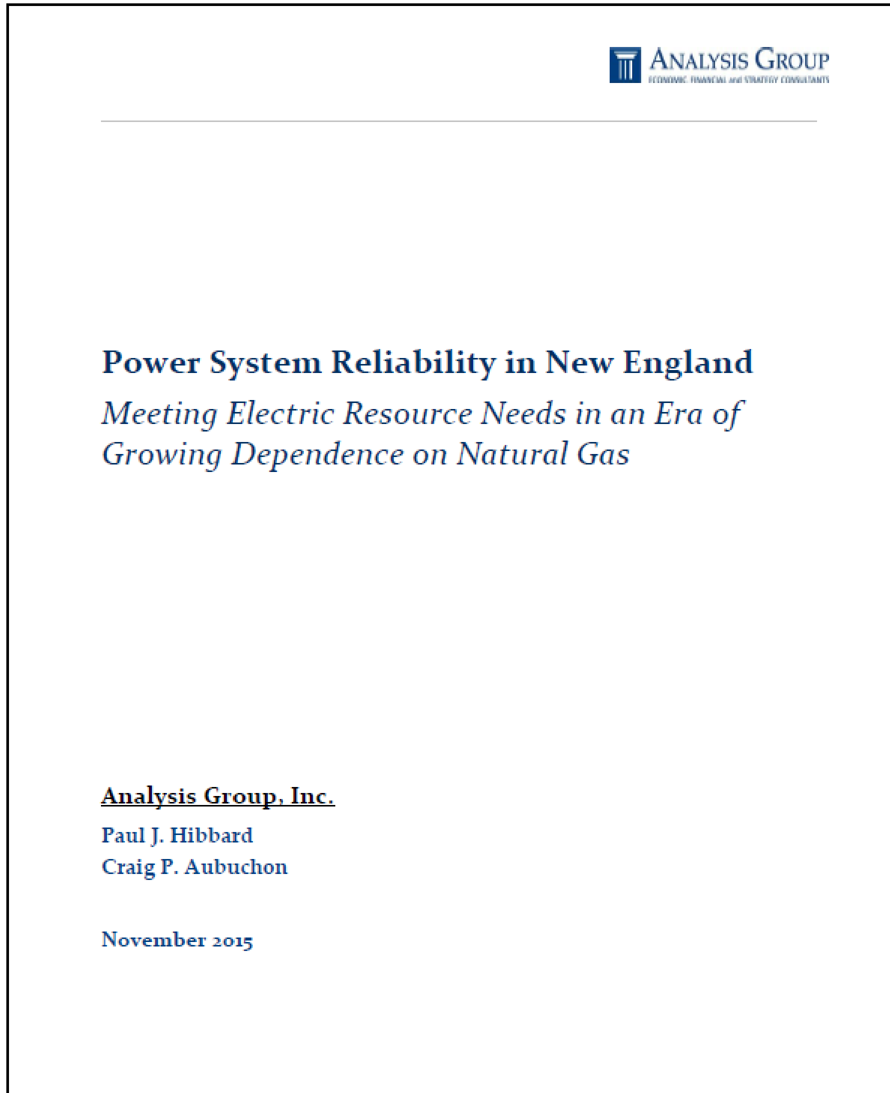
# Regional Electric Options Study

**Paul Hibbard**

December 17, 2015

# Study

- Evaluation of need for and benefits/impacts of future scenarios to meet regional power system needs (with a focus on winter)
- Commissioned by the Office of the Attorney General, Massachusetts, with funding from Barr Foundation
- Stakeholder Advisory Group facilitated by Dr. Jonathan Raab – provided valuable feedback, but all judgments, analysis and findings are those of the authors only
- Today: summary of report. All comments are mine, and do not necessarily reflect positions of AGO, SAG, or Dr. Raab



Analysis Group

**Power System Reliability in New England**

*Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*

**Analysis Group, Inc.**

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Craig P. Aubuchon

November 2015

- http://www.analysisgroup.com/news-and-events/news/report--solutions-to-new-england-s-future-power-system-needs-reflect-tradeoffs-among-ratepayer-costs,-risks,-and-regional-climate-policies/

# Overview

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- Purpose and scope
- Approach
- Deficiency analysis
- Solution sets
- Results
- Observations

# Purpose and Scope

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## Purpose

- Evaluate the need for, and options to address, potential power system reliability deficiencies during winter months
  - **Recognizing constraints on availability of natural gas for power generation**

## Scope

- ~~*Need or resources for natural gas LDC demand (current or future)*~~
- ~~*Construction of natural gas transportation capacity on spec*~~
- **Investment by electric ratepayers to meet identified winter power system needs – with incremental natural gas transportation capacity or otherwise**
  - AGO comments in D.P.U. Docket 15-37, "Investigation by the Department of Public Utilities into the Means by which New Natural Gas Delivery Capacity may be added to the New England Market"
    - "Determine, based on consistently applied economic metrics, which combination of legally available options, including market solutions, most cost effectively addresses the need while maintaining system reliability and meeting climate and other environmental requirements."

# Overview

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## Focus: Power System Needs

- Starting from today, how might New England's power system evolve to maintain reliability?
  - Winter conditions in particular
  - Multiple resource options, grid-level and distributed, gas and non-gas, associated infrastructure

## Identify need, options, relative impacts

- With a statement of future conditions, identify plausible outcomes of markets and/or regulatory action
- Sized & configured at a minimum to the level of need, recognizing sensitivities
- Assess costs and emissions
  - Ratepayer impacts (costs, price suppression benefits)
  - Greenhouse gas (GHG) emissions

# Perspective

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## Do not "*assume in*" a problem

- Only gas-fired generation possible is that supported by current and known future pipeline transportation capacity
  - Assumes no existing multi-year firm, deliverable gas supply/transportation (pipeline or LNG) to power plants
  - *Possibility of* new pipeline capacity, LNG committed for electricity generation during winter peak are evaluated as potential solutions

## Do not "*assume away*" a problem

- Reliability assessment applies difficult winter conditions
- Demand, supply assumptions consistent with what is reasonably known today, and used for reliability planning purposes
- Policy and technology context based on today's conditions, policies
  - *Possibility of* advanced policy & technology, transmission/imports evaluated as potential solutions

## Baseline assumption: market incentives (scarcity, performance) influence *status-quo* outcomes

- Increasing reliance on oil, dual fuel and/or LNG
- Status quo outcome evaluated as solution set

# Approach

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**Deficiency Statement**

- Focus on electric system (MW)
- Winter needs (year-round review)
- Net of non-gas & firm-gas resources
- Characterized by nature of need (magnitude, duration, timing)

**Solution Sets**

- Resource options – pipeline, LNG (contracts, new vaporization), dual-fuel, EE, RE, demand response
- Characterized by nature of capability (magnitude, duration, timing/certainty, development lead time)
- Investment, fixed, variable costs of each
- <u>Combinations</u> ("Solution Sets") that address deficiency

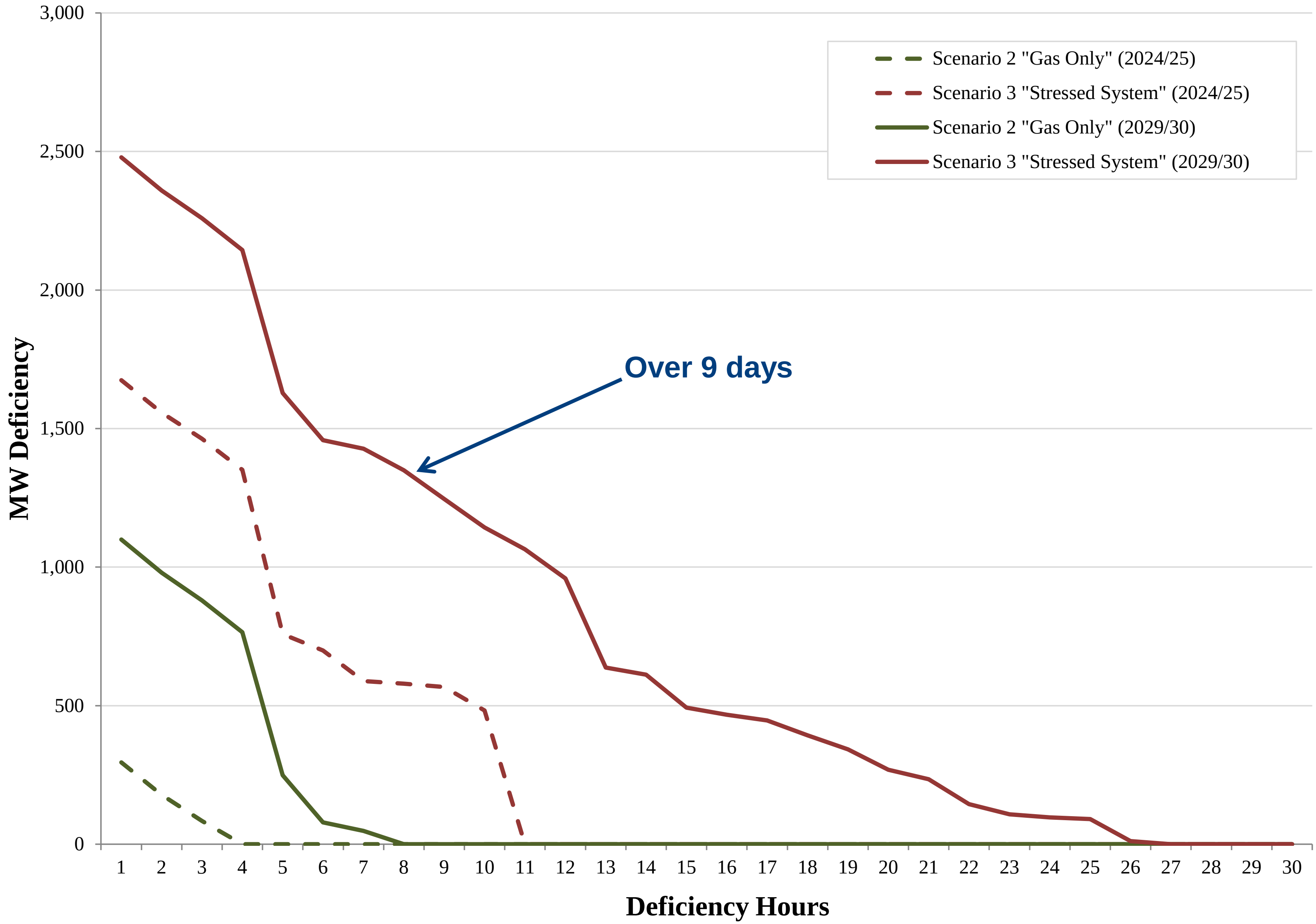
**Assessment**

- Carrying cost, annual fixed costs
- Production costs, load costs
    - *PROMOD, statistical gas price model*
- Ratepayer impacts
- Emissions of greenhouse gases (GHG)

**Evaluation**

- Results (costs, GHG)
- Key uncertainties
- Observations & conclusions

# Stressed System Deficiencies



## Solution Sets

- Solution sets need to meet the minimum requirement, and match the magnitude, frequency and duration of potential need
- Consider three outlooks:
  - “Business as usual” outcomes that would flow from existing market incentives to ensure operations during times of scarcity (dual fuel, LNG);
  - Investment in incremental pipeline transportation capacity sized to meet reliability need (must be committed for use by electricity generators);
  - Increased investment in energy efficiency, demand response, and renewables (must be available at the time of winter peak)
- Infrastructure scenarios:  pipeline larger/sooner than deficiency need; transmission to access low-carbon resources sooner than deficiency need

# Assessment and Evaluation

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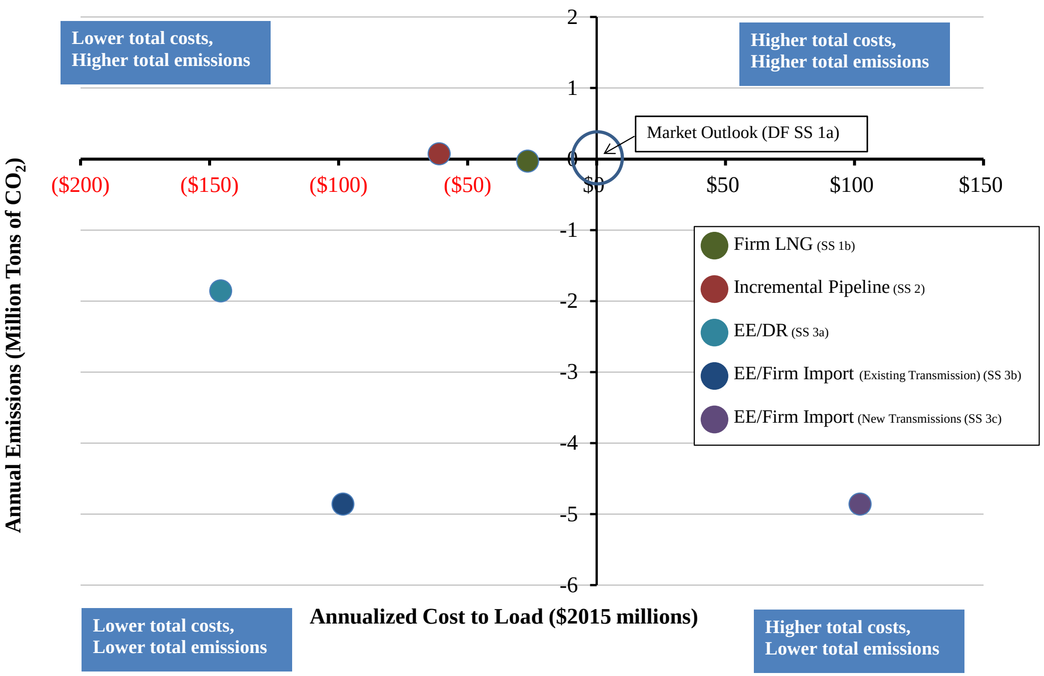
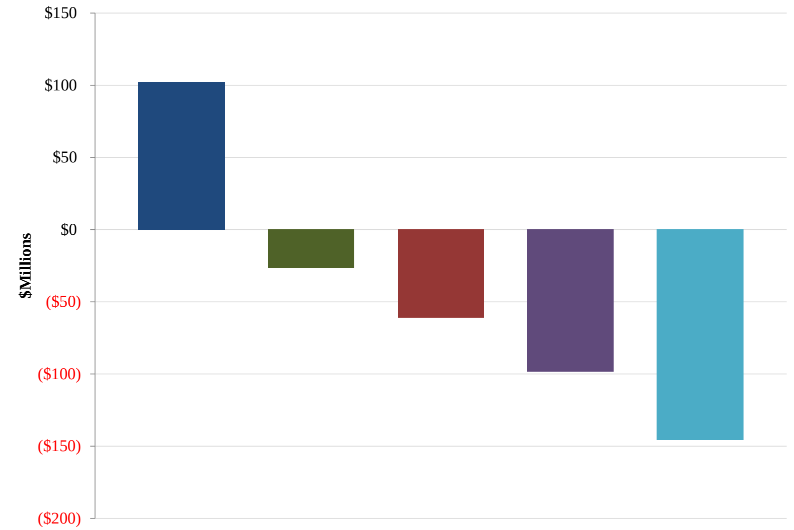
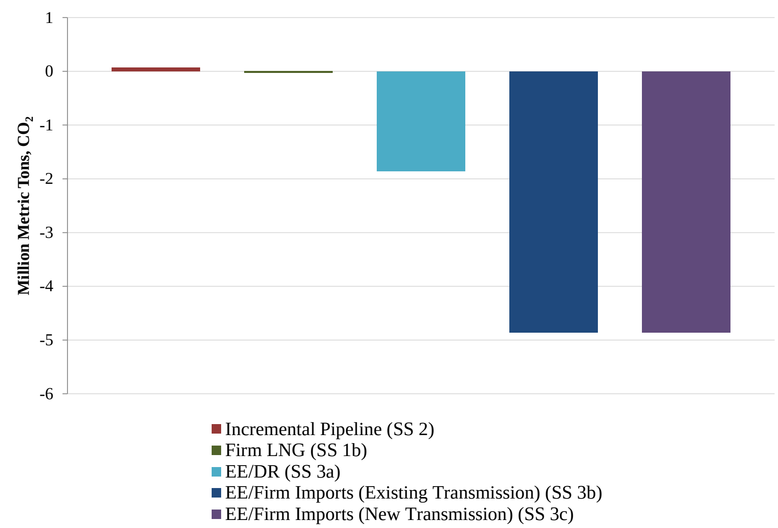
## Assessment and Evaluation includes three primary steps

- Gas Price Model: estimated impact of solution sets on market outlook fuel prices
- Electric Sector Production Cost Model: estimated impact of solution sets (including fuel prices) on:
  - Locational Marginal Prices (LMPs) and Cost to Load
  - GHG Emissions
- Financial Analysis: Total net ratepayer impact includes *both* changes in cost to load *and* costs to implement incremental solution sets




Note: Pipeline solutions include an estimate for incremental in-region GHG emissions from fugitive methane leaks.



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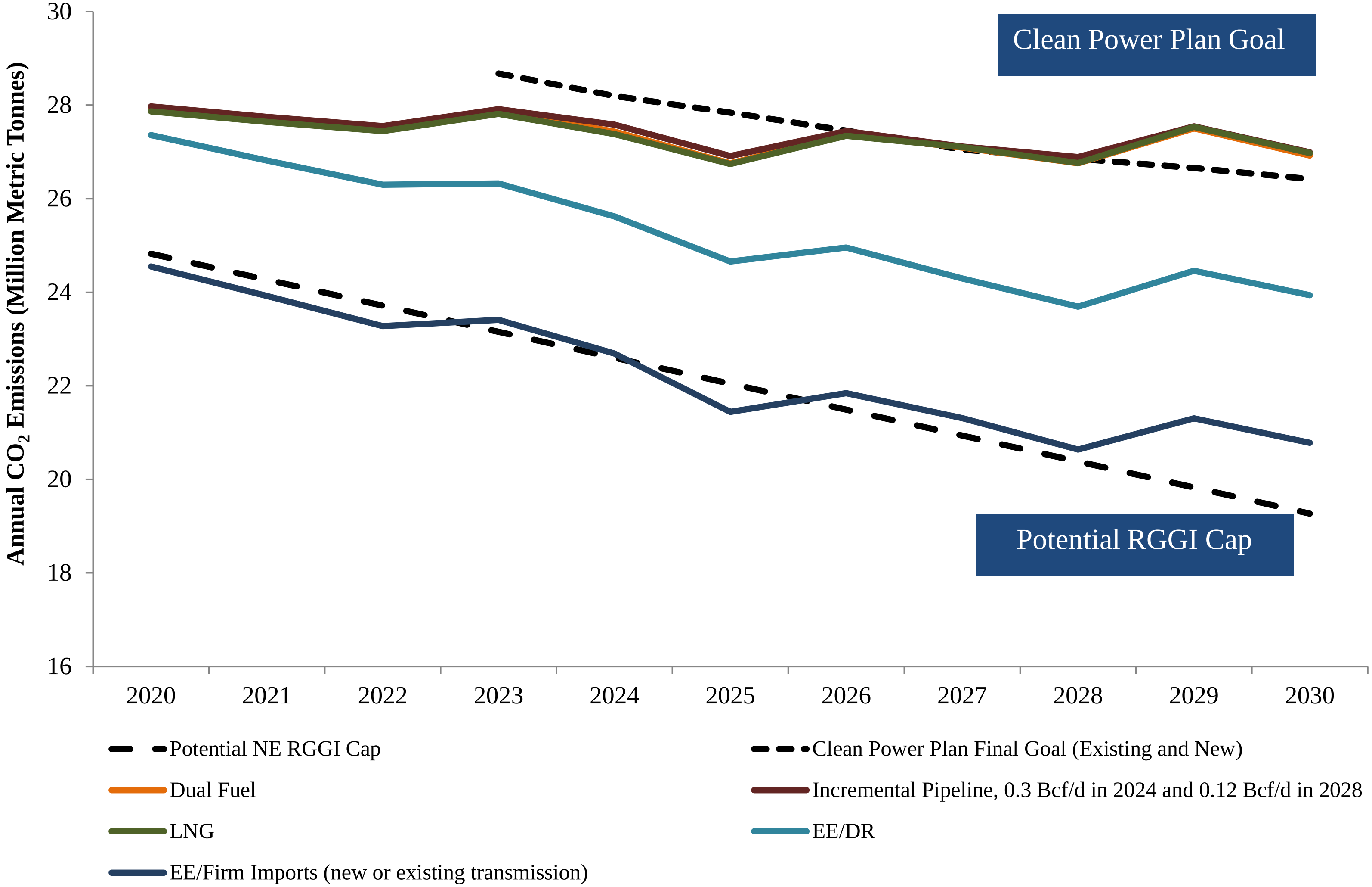


Note: Pipeline solutions include an estimate for incremental in-region GHG emissions from fugitive methane leaks.

# Other Considerations

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## Many tradeoffs

- Markets versus state approach
- Up-front investment versus adjustable annual costs
- Shades on levels of reliability
- Siting/permitting
- Installation/ramping challenges
- Out-of-region GHG implications

| Solution Set | Other Considerations |
|---|---|
| ***Market Driven Outcomes*** | |
| SS 1a: Dual-fuel Capacity ("Status Quo") | • No up-front investment and requires no action on the part of legislatures or regulators<br>• Dual-fuel upgrade costs may not be passed on to consumers (unless upgrade cost affects marginal capacity market prices), costs borne by producers represent a reduction in profits<br>• Relying on oil during winter peak periods has only limited impact on winter gas prices; when oil prices are low, economic oil-fired generation can reduce on-site inventories leading into stressed winter conditions<br>• Air quality permits often restrict total hours of oil-fired operation, though restrictions generally allow more hours of operation than needed to address winter peak reliability needs<br>• Operation time at units will be limited by the quantity and size of oil storage tanks, ability to switch from gas to oil, and ability to replenish supplies, which can be challenging during extreme cold periods |
| SS 1b: Firm LNG Capacity | • No up-front costs to consumers; implementation costs reflected in energy market prices on as-needed basis<br>• LNG use targeted to deficiency may have only limited impact on winter delivered gas prices<br>• Creates flexibility with respect to intra-annual operations and allows for 5 year lead time for renegotiation or pursuit of alternative solution sets if needed<br>• Contract prices and terms are untested at this point; firm commitments remain dependent on contract language and financial penalties; imports constrained by global price risk, global supply production risk<br>• Prices ultimately would be set by few suppliers with limited competition |
| ***Incremental Pipeline Capacity*** | |
| SS 2: Incremental Pipeline: | • Major up-front investment creates long-term ratepayer cost obligation; obligation remains even if use or value of assets diminish or is limited for any reason (e.g., evolution of GHG reduction goals/obligations)<br>• Increased certainty of solution set once approved; known in-service date allows for accountability and tracking of progress made by a single entity<br>• Mechanism to guarantee firm transportation for electricity generation at winter peak is unknown<br>• Increased capacity reduces or eliminates the value of existing capacity release benefits, which may lead to a net loss for gas ratepayers, LDC shareholders, and portfolio managers<br>• Increased in-region flows may be used to serve other markets or LNG exports, potentially increasing pipeline utilization and reducing or eliminating price suppression benefits<br>• Faces significant siting and regulatory challenges, potential local property value impacts and non-GHG environmental impacts<br>• May increase GHG outside New England, and an associated increase in natural gas production and consumption would also increase non-GHG environmental impacts |
| ***Energy Efficiency, Demand Response, and Renewable Energy*** | |
| SS 3a: Energy Efficiency and Demand Response | • Up-front investment is annual, and can be adapted on an annual basis in consideration of actual need and changes in technology, policy and cost factors; actual technologies/programs relied on could adjust in response to technology and cost breakthroughs<br>• Requires a sustained commitment by states for investment, likely over many years; absent a commitment the EE/DR solution cannot be counted on to meet deficiency in later years<br>• Realization could be limited by ability to ramp up resources and providers; full suite of benefits are not immediately available<br>• Requires robust monitoring and verification to ensure expected winter peak impacts are being realized<br>• Annual costs are not certain – could either grow or decline in later years |
| SS 3b/c: Energy Efficiency and Firm Imports (existing and new transmission) | • (See above in SS 3a regarding EE)<br>• Major up-front investment creates long-term ratepayer cost obligations; ratepayer obligation remains even if use or value of assets diminish or is limited for any reason<br>• Must guarantee and price firm winter/year-round capacity; otherwise, cannot be counted on to address deficiency; availability and cost of a firm winter deliverable product is unknown |

# Wrap up

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- Incredibly complicated economic, policy, and environmental challenge for the region
- Models are … well, models
  - *Focus* of analysis is important
- Markets will preserve reliability, but will not necessarily produce outcomes consistent with policy maker objectives
  - Yet interference with market outcomes has its own risks
- State-driven efficiency, pipeline, and transmission approaches all produce market price benefits
- Efficiency, renewable paths are the only ones consistent with long-term climate objectives

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# Deficiency Statement

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## System as it is known today, under base case and stressed system conditions

- Electric load: CELT 90-10 net of EE/PV
- Resource Adequacy
  - Full availability of oil and dual fuel resources
  - Known retirements/additions
  - Assumed EFORd for all units
  - Require a 2 GW reserve at all times
- Available gas for electricity generation
  - Assume cold weather year (2004) gas demand
  - Estimate daily availability on pipeline system for electricity generation, net of other use
- "Stressed System" sensitivities
  - Oil-fired generation not available
  - Incremental retirements replaced with gas-only resources

- ***No deficiency in base case***

# Deficiency Results

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**Total Hours with a Deficiency**

| 2004 Weather Year, 90-10 Load | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 |
|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 1 "Oil Unavailable" | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 2 "Gas-Only" | 0 | 0 | 0 | 0 | 3 | 4 | 4 | 4 | 4 | 7 |
| Scenario 3 "Stressed System" | 0 | 0 | 2 | 3 | 10 | 9 | 13 | 15 | 19 | 26 |

**Total Days with a Deficiency**

| 2004 Weather Year, 90-10 Load | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 |
|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 1 "Oil Unavailable" | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 2 "Gas-Only" | 0 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 3 |
| Scenario 3 "Stressed System" | 0 | 0 | 1 | 2 | 4 | 4 | 5 | 7 | 7 | 9 |

**Peak Hour Deficiency (MW)**

| 2004 Weather Year, 90-10 Load | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 |
|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 1 "Oil Unavailable" | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 2 "Gas-Only" | 0 | 0 | 0 | 0 | 296 | 576 | 699 | 433 | 743 | 1,100 |
| Scenario 3 "Stressed System" | 0 | 0 | 185 | 435 | 1,675 | 1,955 | 2,078 | 1,813 | 2,122 | 2,479 |

**Peak Hour Deficiency (Bcf/hr)**

| 2004 Weather Year, 90-10 Load | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 |
|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 1 "Oil Unavailable" | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scenario 2 "Gas-Only" | 0 | 0 | 0 | 0 | 0.0021 | 0.0041 | 0.0050 | 0.0031 | 0.0053 | 0.0078 |
| Scenario 3 "Stressed System" | 0 | 0 | 0.0013 | 0.0031 | 0.0119 | 0.0139 | 0.0148 | 0.0129 | 0.0151 | 0.0176 |

# Solution Set Summary



| Solution Set | Description | Key Assumptions |
|---|---|---|
| ***Market Driven Outcomes*** | | |
| SS 1a: Dual-fuel Capacity | Annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 | • Annualized costs of $6,856/MW |
| SS 1b: Firm LNG Capacity | Firm delivery of LNG dedicated for electricity generation with a 5-year contract and rolling renewals; Annual contract quantity available in increments of 3 Bcf. | • Contract includes daily demand charge and variable costs indexed to Henry Hub, plus relevant adders |
| ***Incremental Pipeline Capacity*** | | |
| SS 2: Incremental Pipeline | Incremental capacity added incrementally to meet need; 0.3 Bcf/day in 2024 and 0.12 Bcf/d in 2028 | • Costs indexed to proposed pipelines, maximum reservation charge of $39/dth-month<br>• Total capital costs of $788 million, first year costs of $140 million (0.3 Bcf/d)<br>• Costs represent full cost of service, including return on equity, taxes, and depreciation |
| ***Energy Efficiency, Demand Response, and Renewable Energy*** | | |
| SS 3a: Energy Efficiency and Demand Response | Total of 1,300 MW peak winter Energy Efficiency by 2030, with 950,000 MWh installed annually, 2020-2030.<br>Total demand response of 1,100 MW by 2030 | • Total lifetime costs of $0.067/kWh, including all incentives and participant costs<br>• Demand Response costs indexed to recent capacity market bids |
| SS 3b: Energy Efficiency and Firm Imports (Existing Transmission) | Same EE as SS 3a, plus an additional 1,100 MW of firm imports of distant low-carbon energy. We present total ratepayer costs two ways: assuming imports use existing transmission lines (with no incremental cost) and assuming imports require new transmission capacity. | • Firm imports priced at the levelized cost of new hydropower capacity, using EIA data, $4.3 bn for 1,100 MW capacity facility |
| SS 3c: Energy Efficiency and Firm Imports (New Transmission) | | • Incremental new transmission capacity (SS 3c) available for $1.4 billion, including all cost of service obligations |

# Results

| Solution Set | [1] Cost of Energy (Cost to Load) | [2] Cost to Implement Solution Set | [3] = [2] + [1] Total Ratepayer Impact | Emissions (million metric tons) |
|---|---|---|---|---|
| ***Market Outlook*** | | | | |
| Firm LNG (SS 1b) | -$45 | $18 | -$27 | -0.03 |
| ***Incremental Natural Gas Capacity*** | | | | |
| Incremental Pipeline (SS 2) | -$127 | $66 | -$61 | 0.08 |
| ***Distributed & Renewable Technology*** | | | | |
| EE/DR (SS 3a) | -$247 | $101 | -$146 | -1.86 |
| EE/Firm Imports (Existing Transmission) (SS 3b) | -$502 | $404 | -$98 | -4.86 |
| EE/Firm Imports (New Transmission) (SS 3c) | -$502 | $604 | $102 | -4.86 |

| Scenario | [1] Cost of Energy (Cost to Load) | [2] Cost to Implement Solution Set | [3] = [2] + [1] Total Ratepayer Impact | Emissions (million metric tons) |
|---|---|---|---|---|
| ***Incremental Natural Gas Capacity*** | | | | |
| *SCENARIO* (IS 1) - Larger Pipeline (Sized Above Reliability Need) | -$309 | $176 | -$133 | 0.20 |
| ***Incremental Transmission Capacity*** | | | | |
| *SCENARIO* (IS 2) - Early Transmission (New and Existing Transmission Capacity, Firm Imports, 2,400 MW cumulative) | -$576 | $860 | $284 | -6.65 |