



Gas Demand Response

A Solution to the Electricity/Gas Interface Issue?

A Brainstorming Summit

BY

The Brattle Group/Brown Rudnick LLP

June 4, 2014



THE **Brattle** GROUP

Agenda for the Morning

Time	Topic
8:30 – 9:00	Setting the Stage: Background and Context
9:00 – 9:45	The Potential of Gas DR: How much relative to the problem?
9:45 – 10:00	Coffee Break
10:00 – 10:45	Technical Issues: Can it be done?
10:45 – 11:30	Regulatory and Incentive Issues: What would it take?
11:30 – 12:00	Where to go from here?
12:00 – 1:00	Lunch

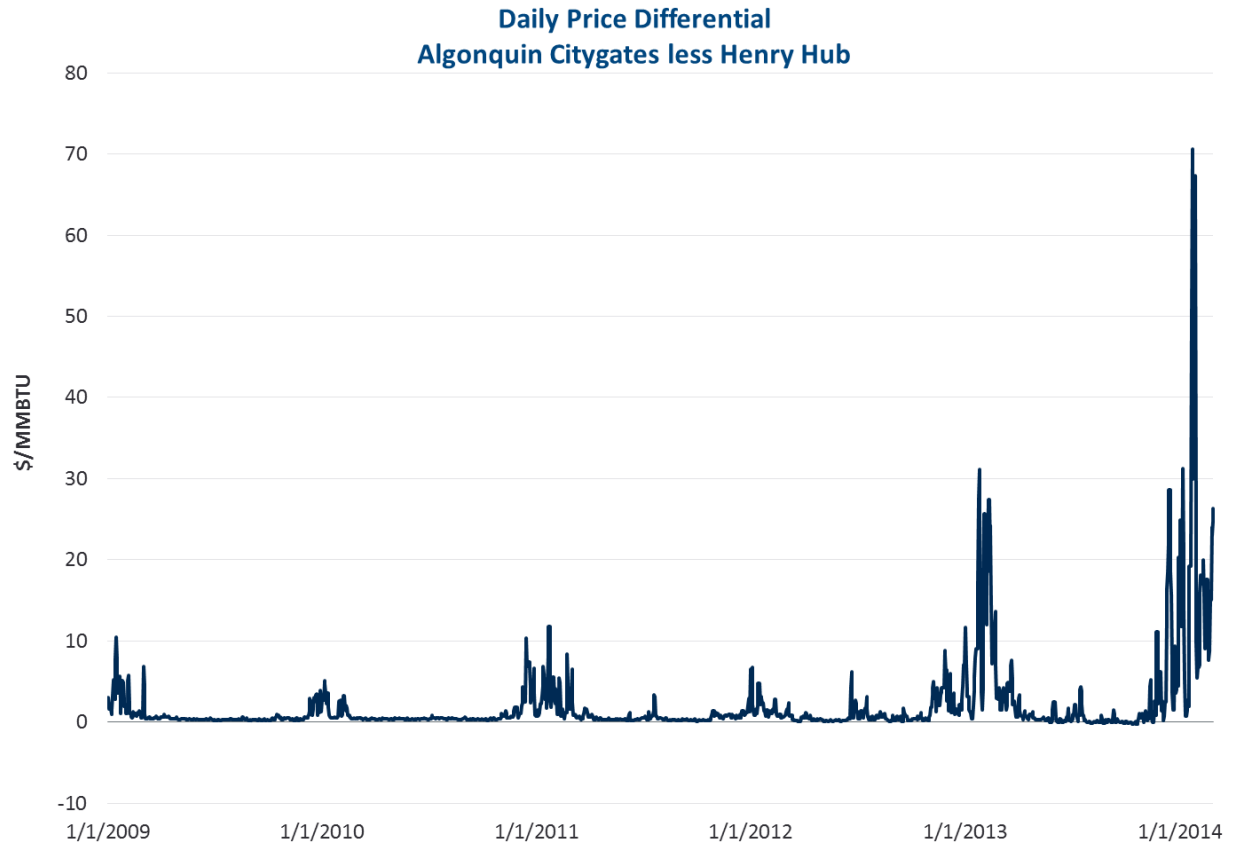
Setting the Stage

Some themes we want to discuss

- The Gas-Electric Interface: What has happened, is happening, or possibly will happen? What are the proposed solutions and how economically do they address the problem?
- Gas DR as a concept: What is it? How is it different from gas EE? Who might be able to do it?
- Is there material “low hanging fruit” on the gas DR side, and if so how much of the problem might it address?
- What are technical issues that exist to make gas DR feasible and that need to be addressed?
- What are the economic barriers or prerequisites (such as new pricing structures)?
- What are the regulatory/incentive hurdles that exist and how could they be addressed?

New England Basis Differentials Are Getting Higher

- Gas pipeline system tight in winter (when LDC load peaks), leading to price spikes
- Price spikes becoming more significant and frequent
- Some summer spikes too, when pipeline maintenance limits capacity and electric sector gas demand is highest



Source: Platts

Consequently, gas-electric interface issue has been emerging in NE and beyond

NESCOE

- +1.0 Bcf/d incremental pipeline (600 MMcf/d above AIM and CT Exp.) and/or 1.2 GW-3.6 GW of incremental transmission for low/no carbon energy into New England
- Working with ISO-NE to develop cost recovery and allocation mechanisms to fund pipeline through a FERC-regulated tariff (IGER concept)

Maine

- Passed H.P. 1128 – L.D. 1559 (Energy Cost Reduction Act) that allows Maine PUC (or distribution companies) to enter into long-term pipeline contracts up to \$70 million/year or 200 MMcf/d.
- Maine PUC currently evaluating whether and how to exercise its authority

ISO-NE

- Proposal to extend Winter reliability program (~\$75 million for 2013/14 winter)
- Proposing Performance Incentives (PI) for capacity markets as longer-term solution

FERC

- Gas-electric coordination docket AD12-12.
- Approved communication standards (Order 787)
- FERC NOPR: multi-party gas contracts, changes to gas operating day, etc.

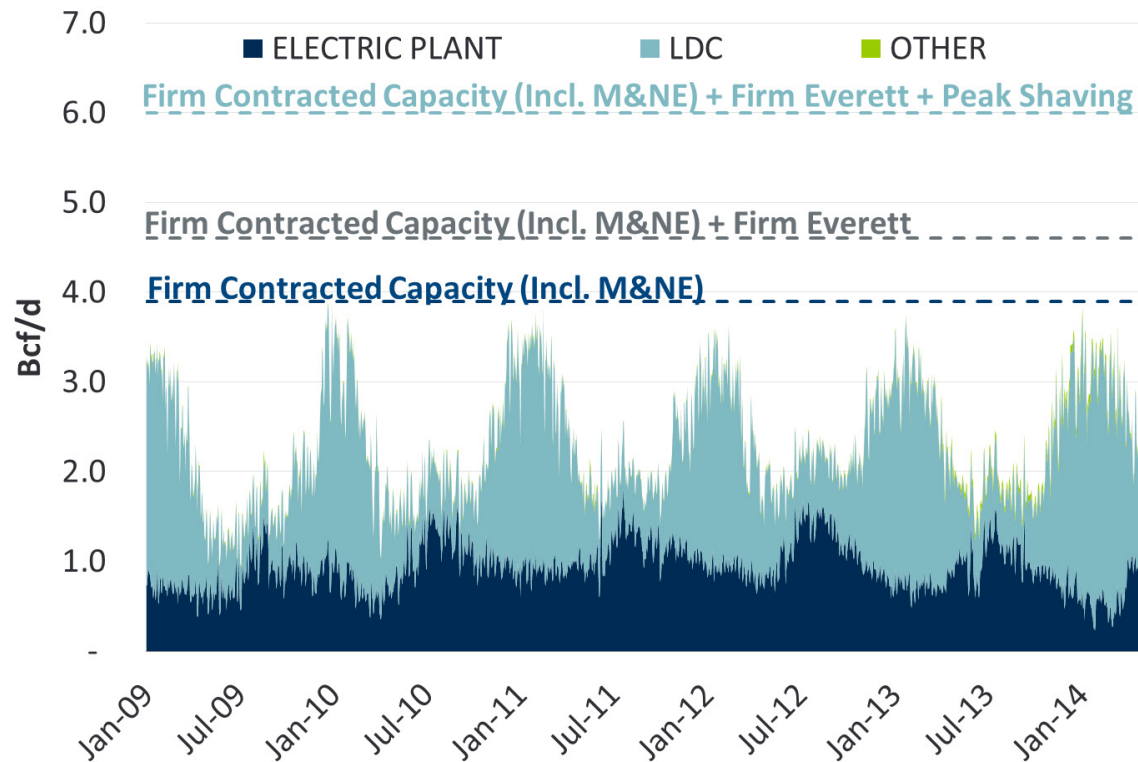
The options considered basically fall into these categories

- Build additional natural gas pipeline capacity
- Build additional LNG peak-shaving storage near demand
- Require dual-fuel capability for gas-fired generation
- Build incremental electric transmission
- ISO-NE initiatives (e.g., winter reliability program, performance incentive, etc.)
- FERC initiatives (e.g., communication standards, scheduling changes)

Many of these options are capital intensive and perhaps at odds with nature of the problem...

- In general, capital investments make most sense if the infrastructure is used often
 - Building infrastructure that is only occasionally needed is costly
- Fixed Infrastructure makes sense to be built for some level of peak demand
 - Even that is becoming less obvious with electric DR
- If a problem occurs only very rarely, you would like to use a “variable cost” solution rather than deploy capital
- Since the BTUs used for non-electric use are very significant, should we look to short term reductions in gas use in addition to short-term reductions in electric use?

...since gas Pipeline Scheduled Deliveries are highly seasonal and weather dependent



Source: Ventyx EV Fuels database. Capacity data from December 2012 NESCOE Phase I report.

- 2 primary pipelines (Algonquin and Tennessee)
- Additional supplies from Maritimes & Northeast, Iroquois, and Portland Natural Gas
- Largest demand in MA and CT
- Includes only pipeline deliveries (excludes LNG supplied directly to Mystic power plant and peak shaving supplies behind LDC city-gate)
- Canaport LNG shutdown during periods of low demand (low summer flows on M&NE)

The Potential of Gas DR: How much relative to the problem?

Could gas DR be a (cheaper) alternative

- Additional pipeline capacity (or other capital intensive remedies) may only get used infrequently and for a few hours
- **Def.: Gas DR = temporary reductions of gas demand by the customer, with or without enabling technology/investments**
- Examples might be:
 - Interruptible gas contracts
 - Programmable thermostats controlled by the utility or a third-party provider
 - Direct controlled gas uses
 - DG with alternative fuel supply (back-up generation)
- If already existing or “behavioral”, might avoid significant capital investment relative to other alternatives

Key Questions

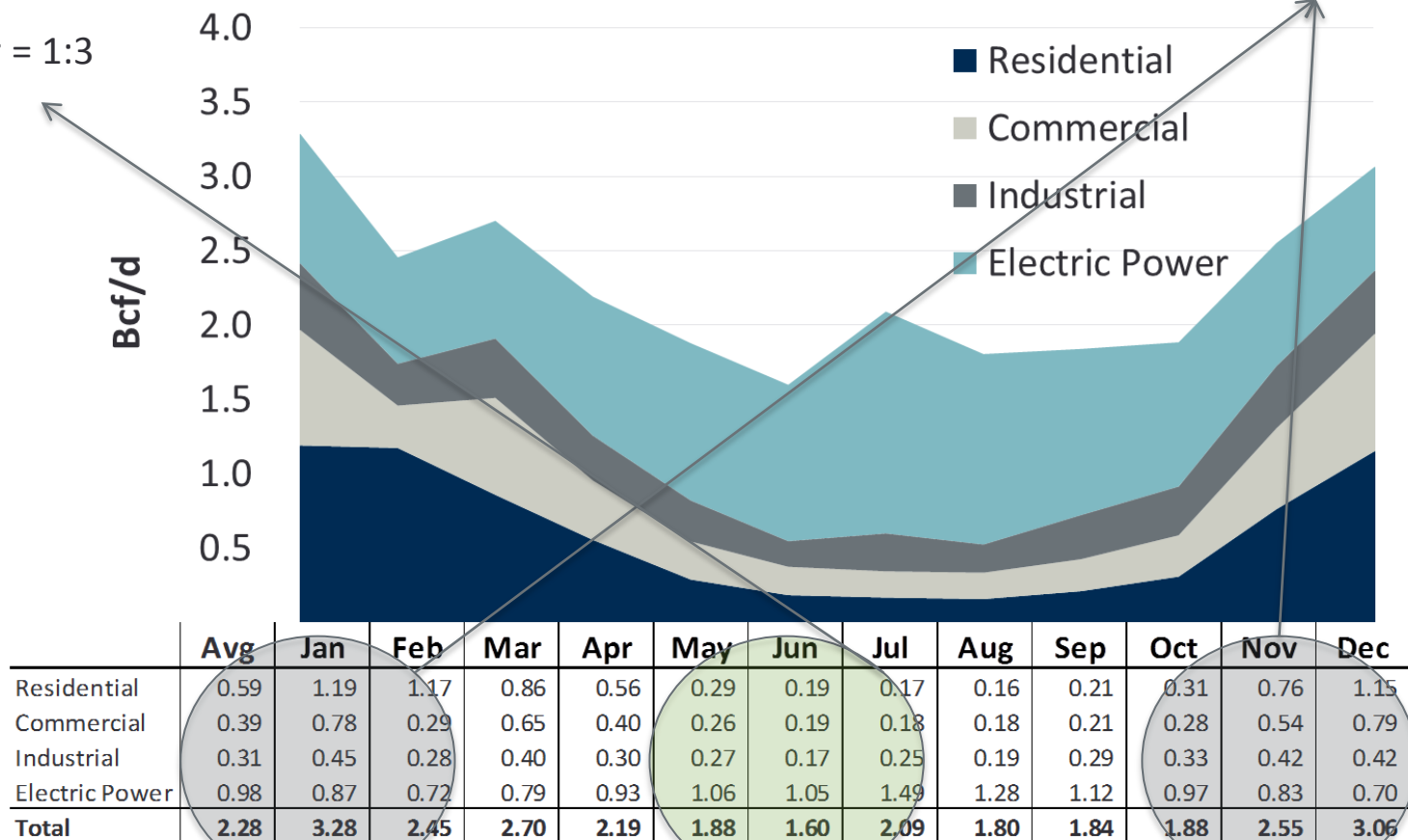
- 1. How much gas DR would be needed to overcome occasional weather-related bottle necks in gas supply (so that we have enough to operate the electric system reliably)?**
- 2. What would be the impact on the non-electric gas use side of reducing gas demand by that amount?**

Tightness occurs mostly in the winter, when heating gas demand >> electric demand

Natural Gas Consumption By Month and By Customer Type in New England -- 2013

Summer:
Heat : Power = 1:3

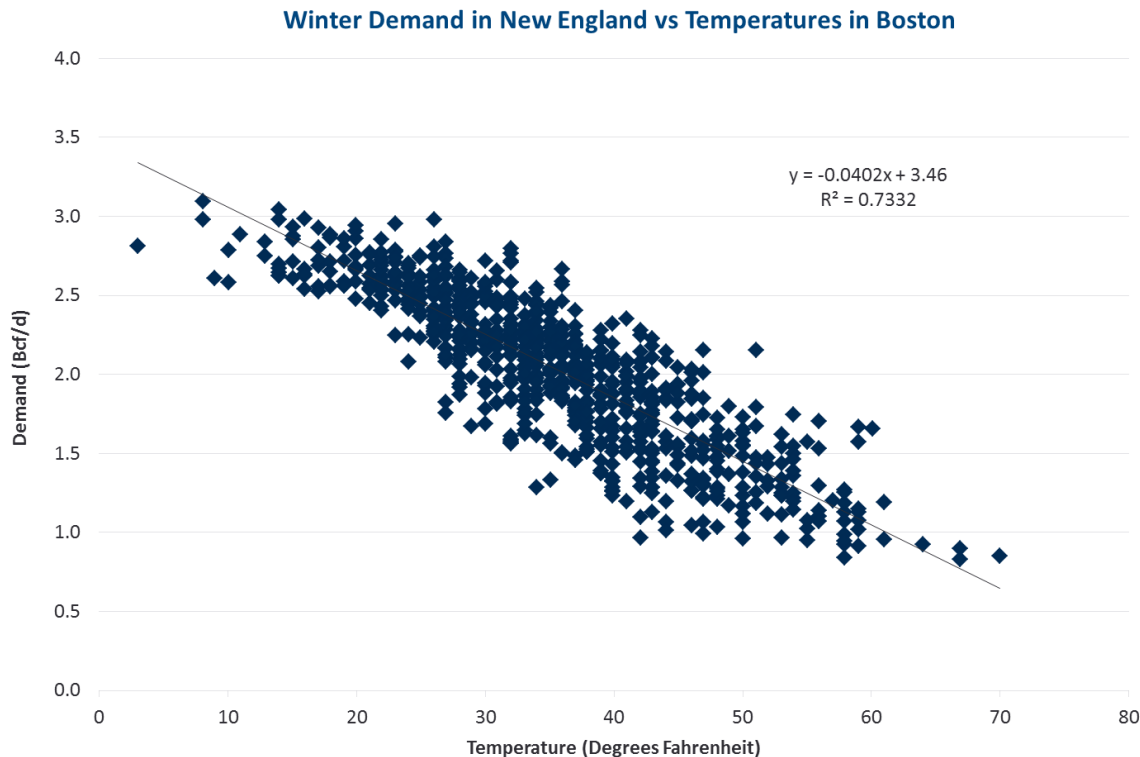
Winter:
Heat : Power = 2:1



Source: EIA

Relationship Between LDC Demand and Temperature

- New England LDC demand is weather driven
- 1 degree (F) reduction in temperature during winter → ~ 40 MMcf/d increase in LDC demand



Sources: Demand data is taken from Ventyx EV Operationally Enhanced Capacity dataset.
Temperature data is from the National Climatic Data Center (NCDC) database.

This may provide some means of estimating the potential impact of gas DR

- Need to assume outside and inside temperature are highly correlated
 - Drop in 1 degree outside has same impact as dropping constant indoor temperature by 1 degree
- If everybody decreased their heating by 1 degree
 - 40 MMcf/day savings
 - About 5% of average power demand for gas during winter

Table 1: Thermostat Change Related Gas Savings in Canada Experiment *)

Strategy	Seasonal	Coldest Day
	Savings	Savings
	%	%
72°F Winter Benchmark	----	----
64°F Nighttime Set-back	6.5	11
64°F Day and Night Set-back	10	17
61°F Day and Night Set-back	13	21

*) Reproduced from Marianne M. Manning , Mike C. Swinton, Frank Szadkowski, John Gusdorf and Ken Ruest; “The effects of thermostat set-back and set-up on seasonal energy consumption, surface temperatures and recovery times at the CCHT Twin House Facility”; NRCC-48361; 2007, Table 4.

Technical Issues: Can it be done?

Key Questions

- 1. What are the technological requirements to make gas DR work?**
 1. How much gas DR potential might exist with current technology already in place?
 2. What incremental investments may be needed to access significant additional potential?
- 2. What might be the cost of putting the needed technology in place?**

DR can take place with multiple technical tools

- Direct load control for electric DR does not require smart electric meters
- New generation of thermostats (NEST, Ecobee, etc.) allow remote control of gas furnace
- Smart meters allow for more sophisticated approaches
 - For electric DR, TOU, CPP, RTP etc.
 - Could have similar options for gas



Regulatory and Incentive Issues: What would it take?

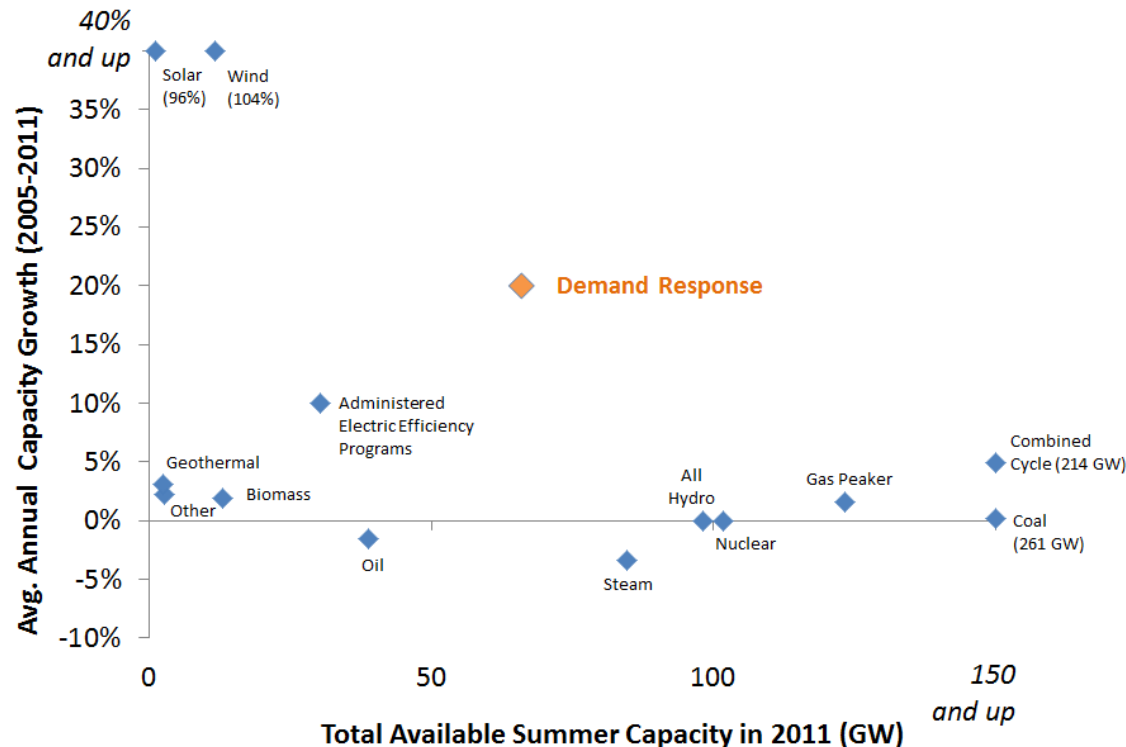
Key Questions

- 1. How does this work for electric DR?**
- 2. What are the current regulatory hurdles to allow a gas DR program? What would need to be changed to create a regulatory environment where gas DR could compete on equal footing with other contemplated measures?**
- 3. Why would a gas user want to participate? What level and kind of incentive would be necessary? Where would the money come from?**

The origins of electric demand response programs

- The early programs, called load management, featured curtailable and interruptible rates for large commercial and industrial customers and direct load control programs for residential customers
- After the California crisis, a new crop of demand response programs made their appearance in much of the country
 - For residential customers, these programs focused on dispatchable dynamic pricing rates; they were spurred on by the rollout of digital meters but deployment of these programs has been slow
 - For commercial and industrial programs, these programs featured aggregator-managed reductions in peak load that were bid into capacity and energy markets

Today, DR is one of the fastest growing resources in the U.S.



Notes:

Source of generation capacity data is Ventyx Energy Velocity Database

Demand response data from FERC 2013 Assessment of Advanced Metering and Demand Response

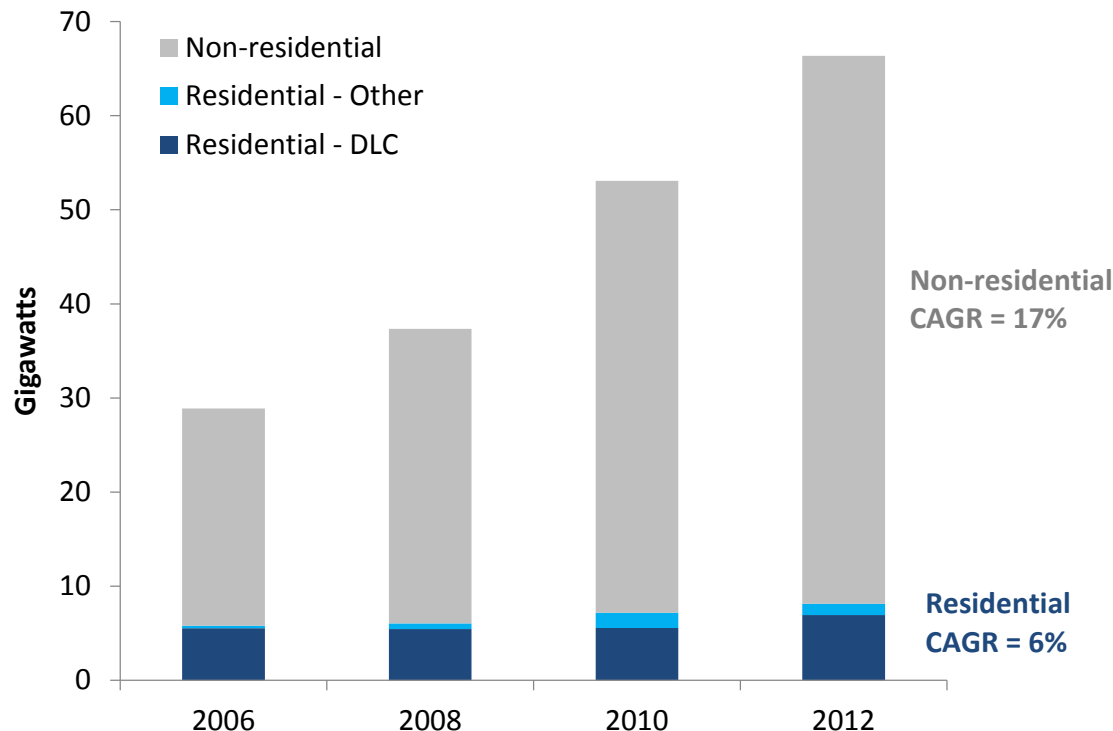
Energy efficiency data based on actual peak reduction estimates from EIA-861

Summer capacity is total for generating units classified as “operating” with commercial online date before January 2012

Assumes 50% peak coincidence for solar and 25% peak coincidence for wind; all other types assume 100% availability for simplicity

The demand response scene is dominated by non-residential programs

U.S. Demand Response Capability



Customer compensation for electric DR varies widely across the programs

- For direct load control programs, customers are often compensated a set amount per month in return for being “on call”
- For programs that use smart thermostats, the compensation is simply the installation of the equipment
- Customers on other programs are paid based on the magnitude of their load reduction
- Hybrid compensation designs are also being implemented

Parallels between electric and gas DR?

- Key Drivers of electric DR participation
 - Participation incentives
 - Per enrollment season
 - Per event
 - Price signals (TOU, CPP, RTP)
 - Rebates (for smart meters, thermostats, etc.)
- How to make gas DR work
 - All but price signal related options should exist today
 - Price Signals/Rates may be trickier
 - What time resolution of rates?
 - Can you compensate gas savers with electricity related savings?

Implications for gas demand response

- Smart thermostats are being rapidly deployed across the country and are expected to replace the compressor switches that are used to control air conditioners; since they control both space heating and air conditioning, they provide a natural avenue for controlling space heating loads
- Other residential loads that could be controlled include water heating and clothes drying
- For commercial and industrial customers, the aggregator model could be extended to control gas use during critical times but a new business model may be needed for the aggregator

Where to go from here?

Summary/Next Steps

- What (if anything) did we learn?
- Was this useful?
- Is there a reason to repeat/expand
 - Deep dives on sub-topics
 - Expand geographic discussion to New England (and beyond)
- Is there a need/desire to “study” some aspect of this offline?
- Is there a benefit to having some regular process/group?
- Other ideas?

About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience, rigorous analyses, and principled techniques to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

- Climate Change Policy and Planning
- Cost of Capital & Regulatory Finance
- Demand Forecasting & Weather Normalization
- Demand Response & Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation & Risk Management
- Energy Contract Litigation
- Environmental Compliance
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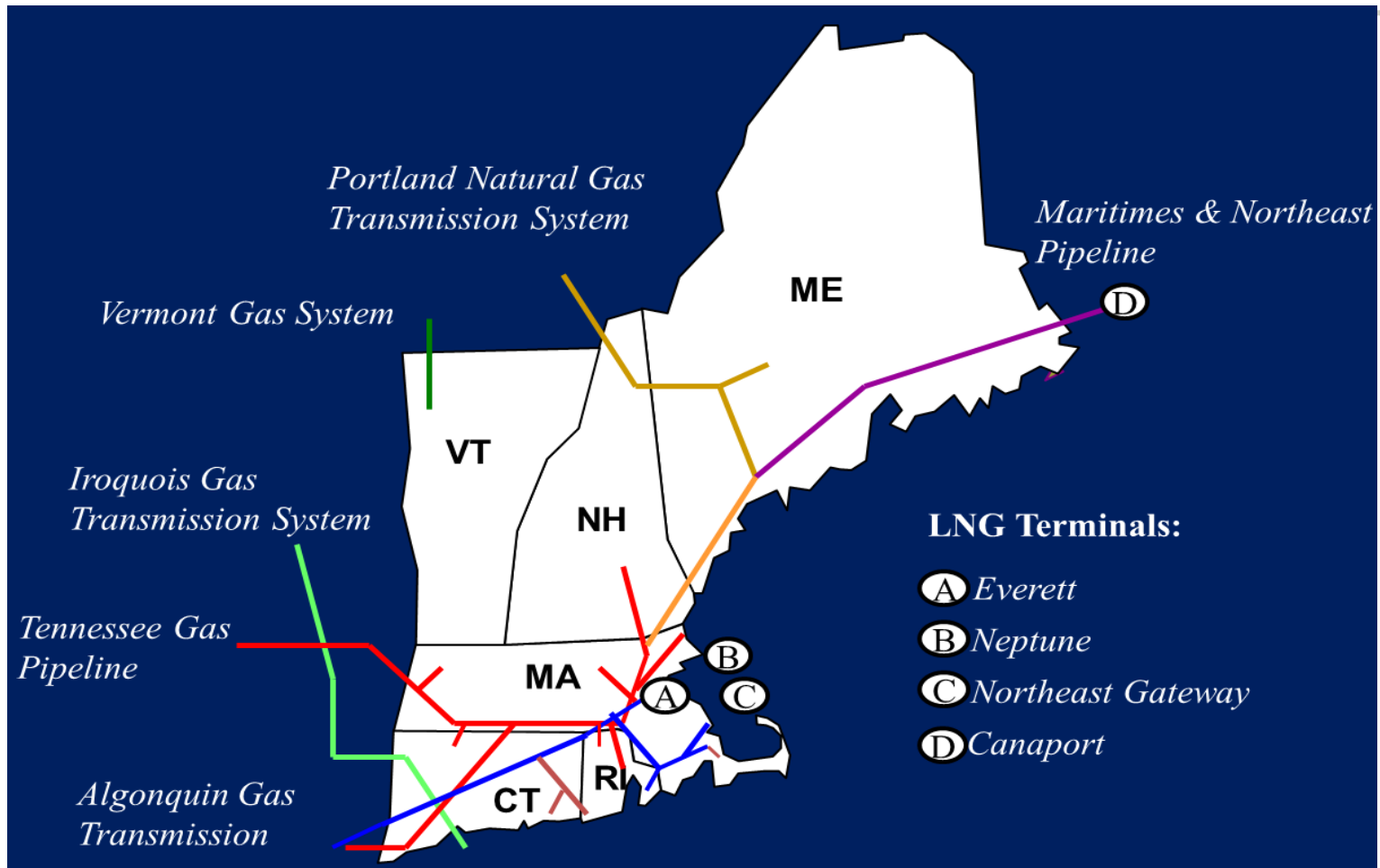
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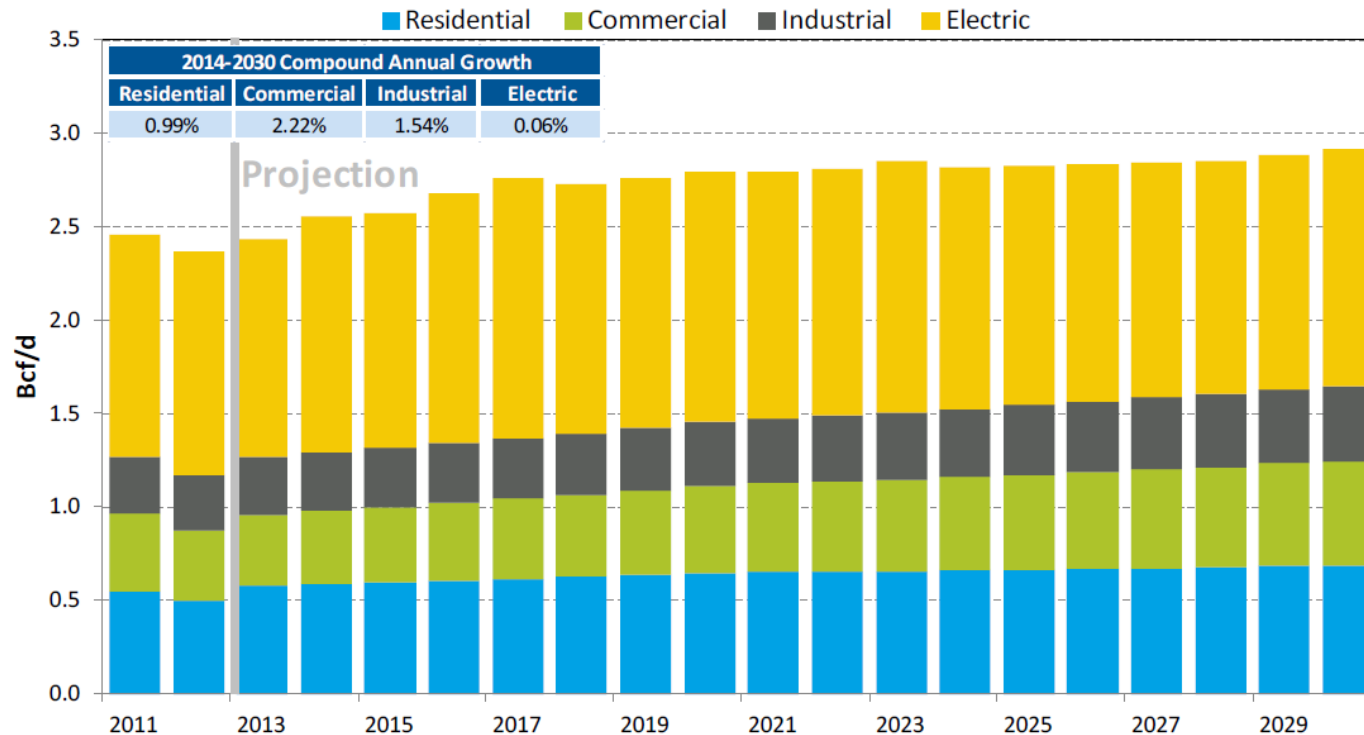
Backup Slides

Existing Interstate Natural Gas Pipelines Serving New England



Sources and Notes: Recreated using map from New England Gas Association presentation titled "Will There Be Enough Gas to Fully Support Electricity Generation in New England?" (2/16/2001) and map of LNG terminals available via FERC (as of 11/1/11).

New England Natural Gas Demand projected to increase further



Source/Notes: Natural Gas Infrastructure and Electric Generation: Proposed Solution for New England, Black and Veatch, prepared for NESCOE, Aug 26, 2013, p. 25. The figure shows the B&V Base Case projections.

- 600 MW VT Yankee operates in B&V Base Case
- B&V High Demand scenario shows growth from 2.5 Bcf/d in 2013 to 3.2 Bcf/d in 2029, and Res/Com from 1.0 Bcf/d in 2013 to 1.4 Bcf/d by 2029.
- Separately, ICF projects Winter Peak Day LDC demand to grow from 4.4 Bcf/d in 2013/14 to 4.8 Bcf/d in 2019/20.

Expected Changes

Pipeline Capacity

- Likely: +410 MMcf/d (340 AIM + 70 TGP CT Expansion)
- Proposed: Spectra Atlantic Bridge (100 – 600 MMcf/d), TGP Northeast Expansion (600 – 2,200 MMcf/d), and PNGTS C2C Expansion (120 – 150 MMcf/d)

Electric Transmission

- Proposed: 1.2 GW – 3.6 GW NESCOE and/or 1.2 GW Northern Pass

LDC Gas Demand / Oil-to-Gas Conversions

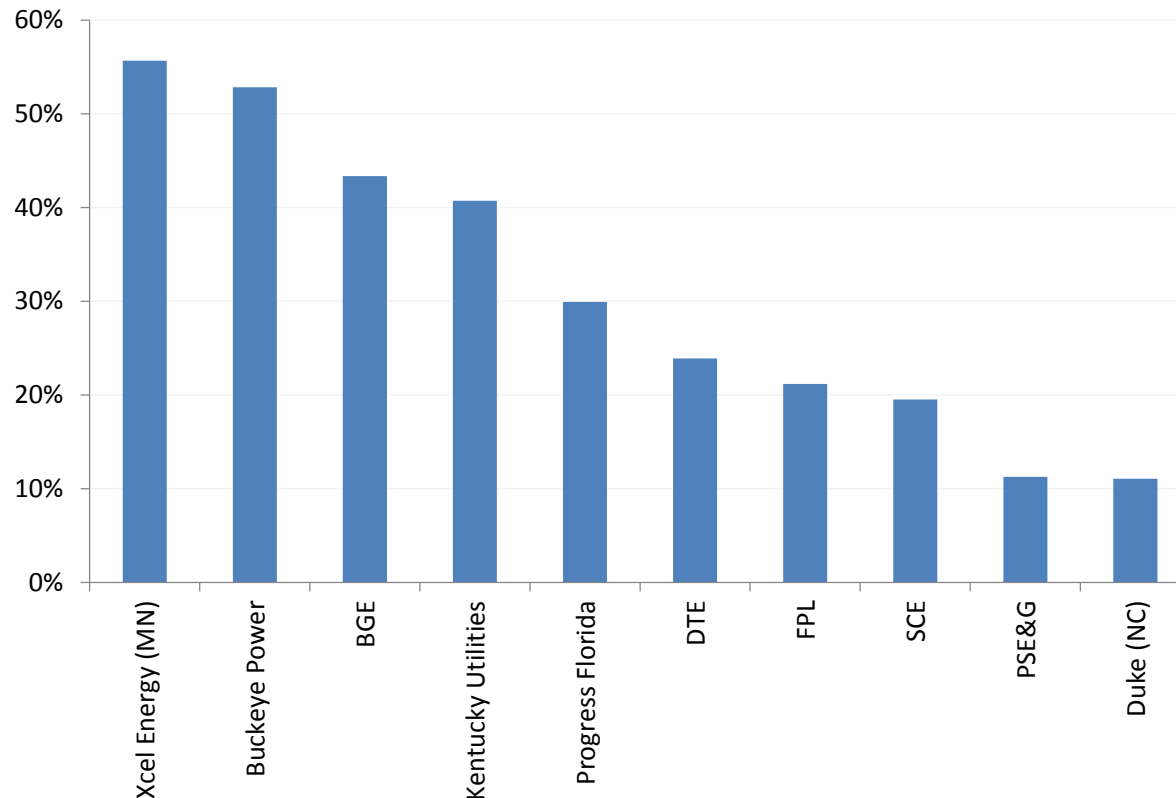
- ICF: +400 MMcf/d in Winter Peak Day demand between 2013/14 and 2019/20
- B&V High Demand Case: +400 MMcf/d in avg Res/Com demand between 2013-2029

Gas Demand in Electric Sector

- Retirement of VT Yankee nuclear (600 MW), Salem Harbor coal/oil (600 MW), and Norwalk Harbor oil (300 MW) by 2014 and Brayton Point coal/oil (1,500 MW) by 2017 → ~+500 MMcf/d equivalent
- Renewables will reduce gas demand (e.g., 1.2 GW Northern Pass project will bring hydro from Canada)

Large residential DLC programs have achieved at least 10% to 30% enrollment rates

Enrollment (% of Eligible) in 10 Largest Residential DLC Programs



Source: FERC 2010 Assessment of Demand Response & Advanced Metering

Note: Utility-level CAC saturations were used where available. Otherwise, state-level estimates were taken from FERC's 2010 Assessment of DR Potential