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NATIONAL RENEWABLE ENERGY LABORATORY

Hydrogen Infrastructure Cost Estimates -&- Blending Hydrogen into Natural Gas Pipelines

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DOE Hydrogen and Fuel Cell Technical Advisory Committee

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Presentation Overview

Hydrogen Infrastructure Cost

- Two recent NREL reports have addressed the topic of hydrogen station costs using new inputs from the Hydrogen Station Cost Calculator (HSCC)
- IDC Energy Insights administered the HSCC
- New data suggest significant cost reductions in the near-term
- A business case study for the Northeast States has been developed

Hydrogen in Natural Gas Pipelines

- The Gas Technology Institute and NREL have generated a new report reviewing the concept of blending hydrogen into natural gas pipelines as a means of both transporting hydrogen and storing/utilizing renewable or stranded hydrogen
- The 5-year *NaturalHy* EU study is a major source of information
- Though a broad range of issues must be taken into consideration, blending as a means of transport (with downstream extraction) or storage is technically feasible and may be economically viable under the right conditions

Hydrogen Infrastructure Cost Estimates

Overview: Hydrogen Infrastructure Cost

Hydrogen Station Cost Calculator (HSCC)

- The HSCC was proposed at an expert stakeholder workshop in February 2011, and was executed by IDC Energy Insights in late 2011. Results were finalized and validated in early 2012 and subjected to various reviews. A report with preliminary results was released in August 2012.*
- The costs reflect generic hydrogen stations expected to be deployed in the 2013-2017 timeframe.

Comparisons to other station costs (sources and estimates)

- A report is in review comparing HSCC results to other estimates of station costs, as well as costs reported from CARB and CEC on stations installed in California.

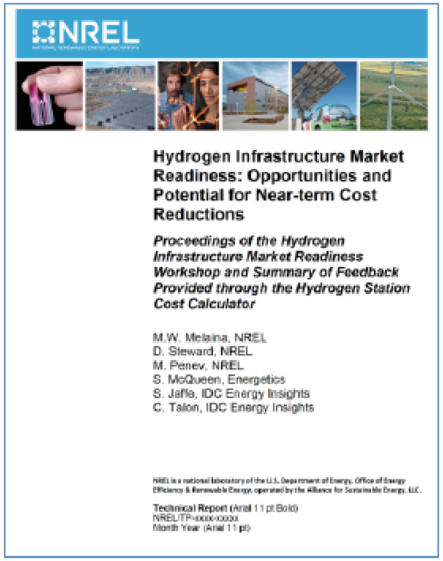
Applying HSCC results to a Northeast Corridor rollout scenario

- HSCC results were used as the cost basis for a dynamic cash flow analysis of fuel cell vehicle and infrastructure deployment in the Northeast states that have adopted the ZEV mandate (CT, MA, ME, NH, NJ, NY, RI, VT).

* Workshop website: http://www1.eere.energy.gov/hydrogenandfuelcells/wkshp_market_readiness.html

Cost reduction opportunities from the Market Readiness Workshop*

Stakeholder engagement and feedback provided concrete guidance on cost reduction opportunities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Hydrogen Infrastructure Market Readiness: Opportunities and Potential for Near-term Cost Reductions

Proceedings of the Hydrogen Infrastructure Market Readiness Workshop and Summary of Feedback Provided through the Hydrogen Station Cost Calculator

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Technical Report (Arial 11 pt Bold)
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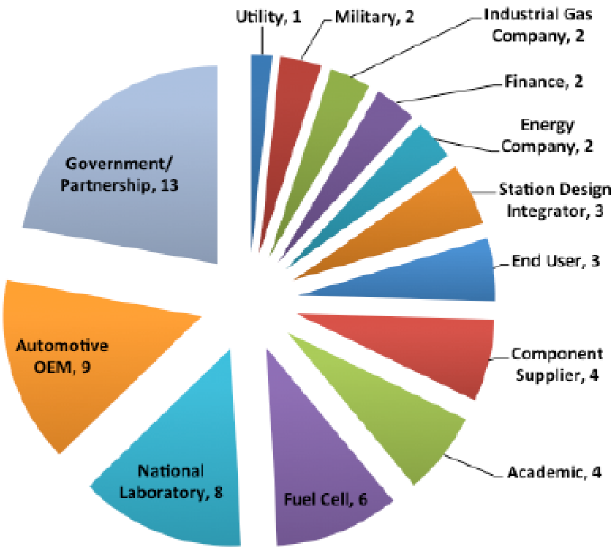
KEY STATION COST REDUCTION OPPORTUNITIES

1. Expand and enhance supply chains for production of high-performing, lower-cost parts
2. Reduce cost of hydrogen compression
3. Develop high-pressure hydrogen delivery and storage components
4. Develop "Standard" station designs
5. Harmonize/Standardize dispensing equipment specifications
6. Develop "Type Approvals" for use in permitting
7. Improve information and training available to safety and code officials
8. Develop mechanisms for planning station rollouts and sharing early market information



Workshop proceedings summarize feedback from over 60 participants from a diverse mix of stakeholder groups

* Workshop website: http://www1.eere.energy.gov/hydrogenandfuelcells/wkshp_market_readiness.html

HSCC framework was discussed at workshop and feedback was collected to improve this tool

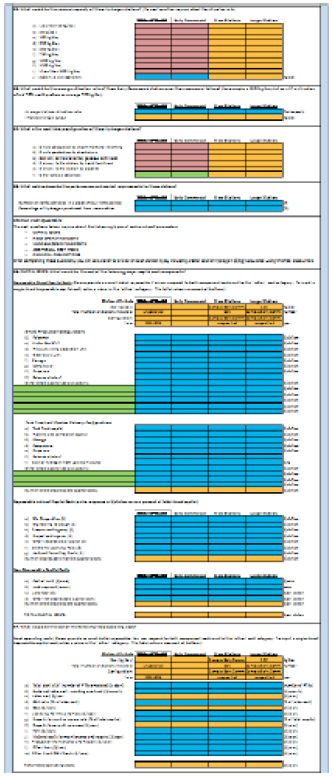
The HSCC was design to quantify particular cost trends

- The HSCC defines 4 station types:
  - State-of-the-art (SOTA)
  - Early Commercial (EC)
  - More Stations (MS)
  - Larger Stations (LS)

Types are defined to isolate cost reductions due to scale, volume and experience

HSCC is designed to shows all four types side-by-side

- Respondents were asked to provide input on any station type (or pathway) applicable to their expertise (gaseous truck, onsite production, etc.)
- At the bottom of the HSCC is a "calculate" button that determines the $/kg result based upon respondent's inputs. Calculation is consistent with H2A.
- Respondents were able to respond to multiple levels of detail in terms of costs and station characteristics. Respondents are also able to provide more aggregate information and still perform the summary $/kg calculations
- Section C is separate from the cost calculation section, and allows respondents to prioritize research funding across the Research, Development, Demonstration and Deployment (RD^3) innovation spectrum.



Screenshot shows 33% of total HSCC

Station types within the HSCC

The deployment year, size and cost of "Early Commercial" stations were all posed as open questions within the HSCC

State-of-the-Art Stations (SOTA). Newly installed hydrogen stations with the following attributes: 1) Installed and operational within the 2011-2012 timeframe, 2) include the most recent generations of major components; but not necessarily include novel or "demonstration" components.

Early Commercial Stations (EC). Installed within the next 5-20 years with the following attributes: 1) The stations are financially viable with little government support, 2) The stations are sized to support growing demand in a promising market region, and to ensure adequate ROI, 3) The station design enables cost reductions because it is replicable.

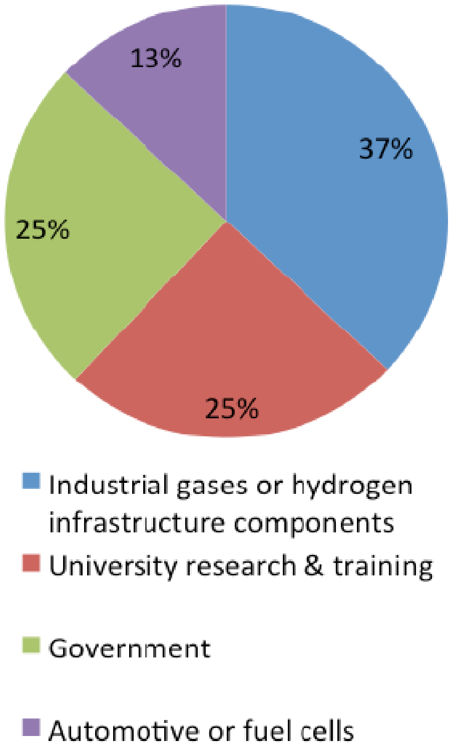
More Stations (MS). Identical to Early Commercial stations, but deployed in larger numbers. Additional cost reductions are achieved through standardization, mass production, streamlining of installation processes and learning by doing.

Larger Stations (LS). Identical to Early Commercial stations, but designed for higher volume output. Default value is a 1.5 increase in size over the Early Commercial stations, with 2000 kg/day as an upper limit.

A diverse set of stakeholder types provided feedback

HSCC responses were weighted and aggregated to develop a generic representation of hydrogen station costs and rollout timeframes

- The HSCC was distributed to a select group of experts
- 11 responses were received from a diverse set of stakeholders (see pie chart)
- Responses were weighted based upon industry experience metrics developed by IDC Energy Insights
    - Responses from stakeholders with more historical experience installing hydrogen stations were weighted more heavily
- Respondent anonymity was maintained throughout the data collection and articulation process
- Given that the HSCC allowed for detailed and varied types of responses, some challenges were posed in synthesizing responses into an aggregate and representative whole
    - Different respondents filled out different parts of the HSCC
    - Aggregated results could not be reported for all cost items



HSCC Respondents by Stakeholder Type

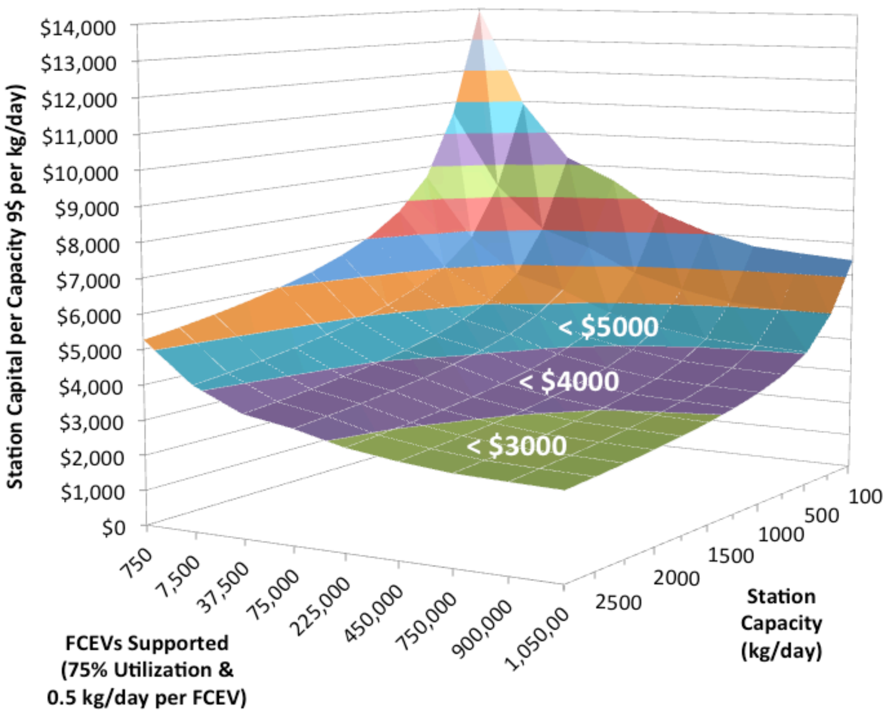
Hydrogen Station Cost Calculator Results, focusing on capital costs

Station Attribute	Units	Station Type			
		State-of-the-Art	Early Commercial	More Stations	Larger Stations
Introduction timeframe	years	2011-2012	2014-2016	after 2016	after 2016
Capacity	kg/day	160	450	600	1,500
Utilization	%	57%	74%	76%	80%
Average output	kg/day	91	333	456	1,200
Total Capital	$M	$2.65	$2.80	$3.09	$5.05
Capital Cost per capacity	$1000 per kg/d	$16.57	$6.22	$5.15	$3.37
reduction from SOTA	%	na	62%	69%	80%

Hydrogen station cost calculator capital cost results as a function of FCEVs supported and station capacity

$$C' = C^o \left(\frac{Q'}{Q^o}\right)^{\alpha} \left(\frac{V'}{V^o}\right)^{\beta}$$

Where,
C' = Station Capital Cost ($/station)
C^o = Base Station Capital Cost ($/station) ($C^o_{EC}$ = $2.65M)
Q' = Station Capacity (kg/d)
Q^o = Base Station Capacity (kg/day) (Q^o_{HSCC} = 450 kg/day)
V' = Cumulative Capacity (kg/day)
V^o = Cumulative Capacity at Cost Status of Base Station (kg/day) (V^o_{HSCC} = 25,000 kg/d)
α = Scaling Factor (α_{HSCC} = 0.707)
β = Learning Factor (β_{HSCC} = -0.106)



Comparisons to other station costs

Results from the HSCC are compared to:

- **Updated H2A forecourt station costs**
- **UC Davis Transition Study (2010) and recent updates (2012)**
- **Recent station installations in California (2009-2013)**

These costs are compared with respect to economies of scale (kg/day) and reductions achieved with time and volume

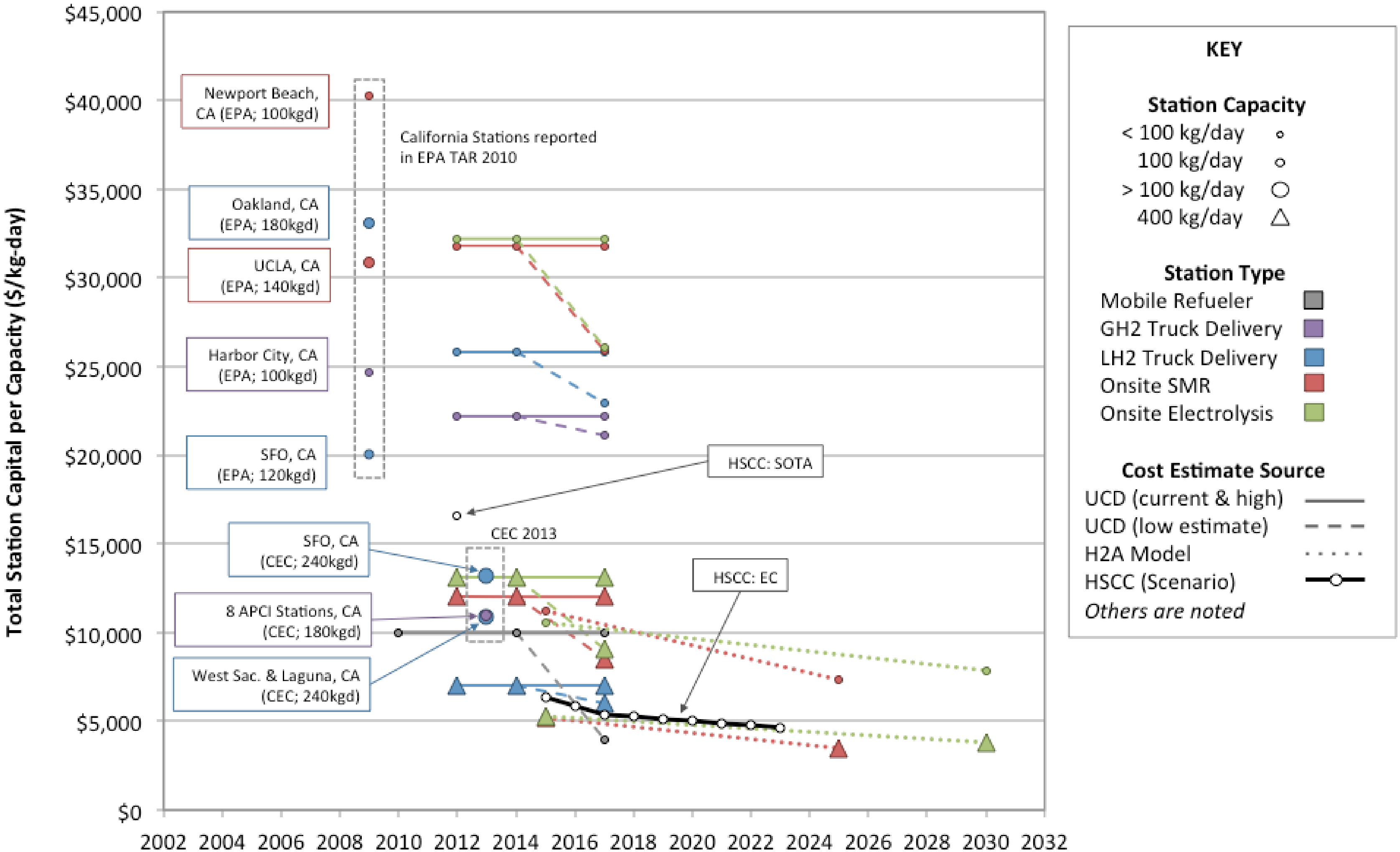
A key metric for comparison is capital per station capacity ($/kg-day)

Early (1996 & 1997) capital cost estimates for onsite SMR and electrolysis stations.

Station Type and Estimate	Capacity (kg/d)	Capital ($M)	Capital ($/kg-d)
Ogden, 1996			
Onsite SMR ("Fuel Cell Reformer")	255	$0.86	$3,381
	933	$1.89	$2,021
	2,550	$5.21	$2,043
Thomas, 1997			
Onsite SMR ("Factory Built")	290	$0.608	$2,095
Onsite Electrolysis	366	$2.051	$5,605
	3,660	$11.812	$3,227

Notes: costs converted from original dollar values (1997 for Thomas and 1996 for Ogden) using the Chemical Engineering Plant Cost Index (see H2A models).

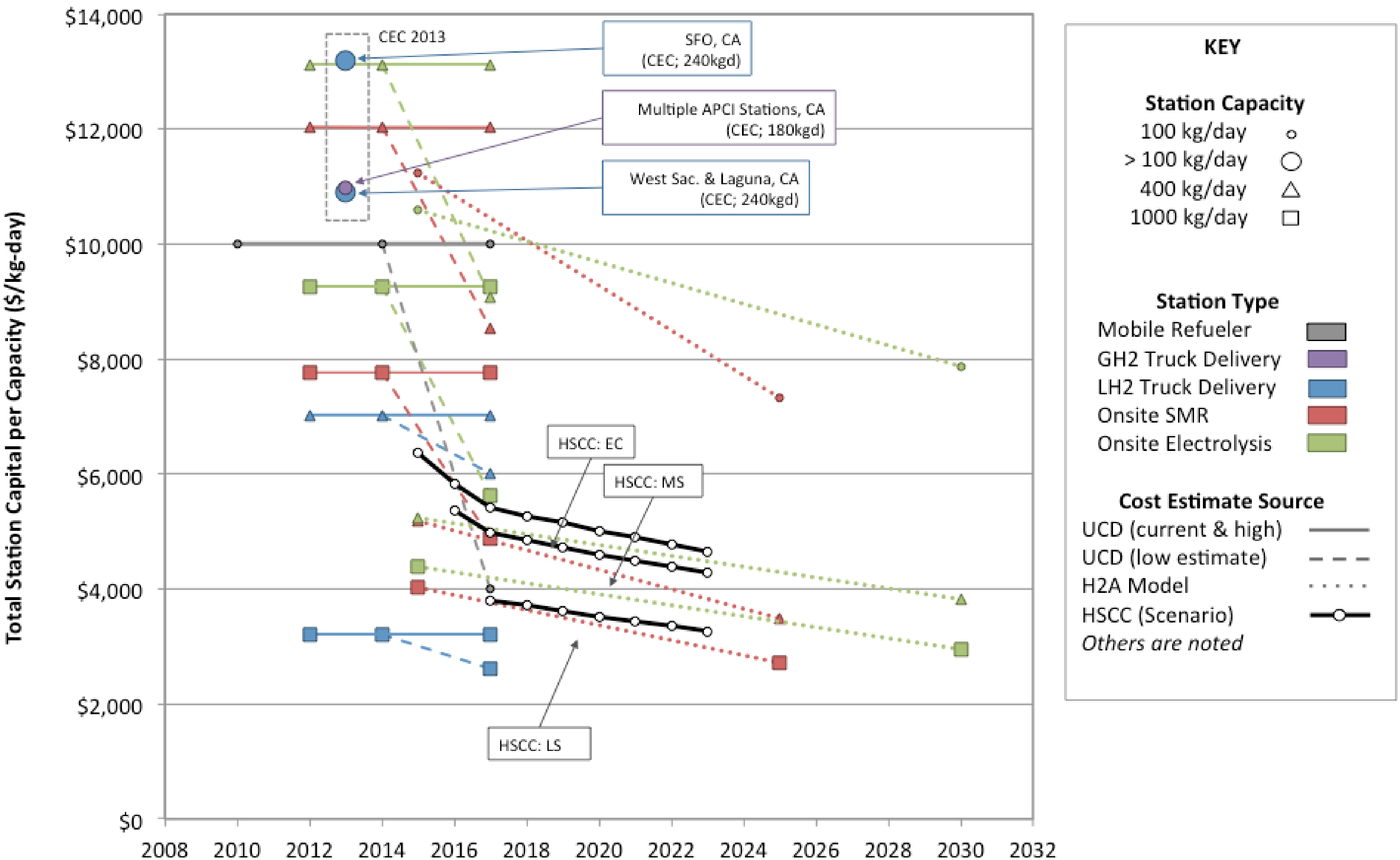
Capital costs per capacity for hydrogen stations over time: focus on smaller, near-term stations



PRELIMINARY RESULTS

Final report expected to be published in late 2012 or early 2013.

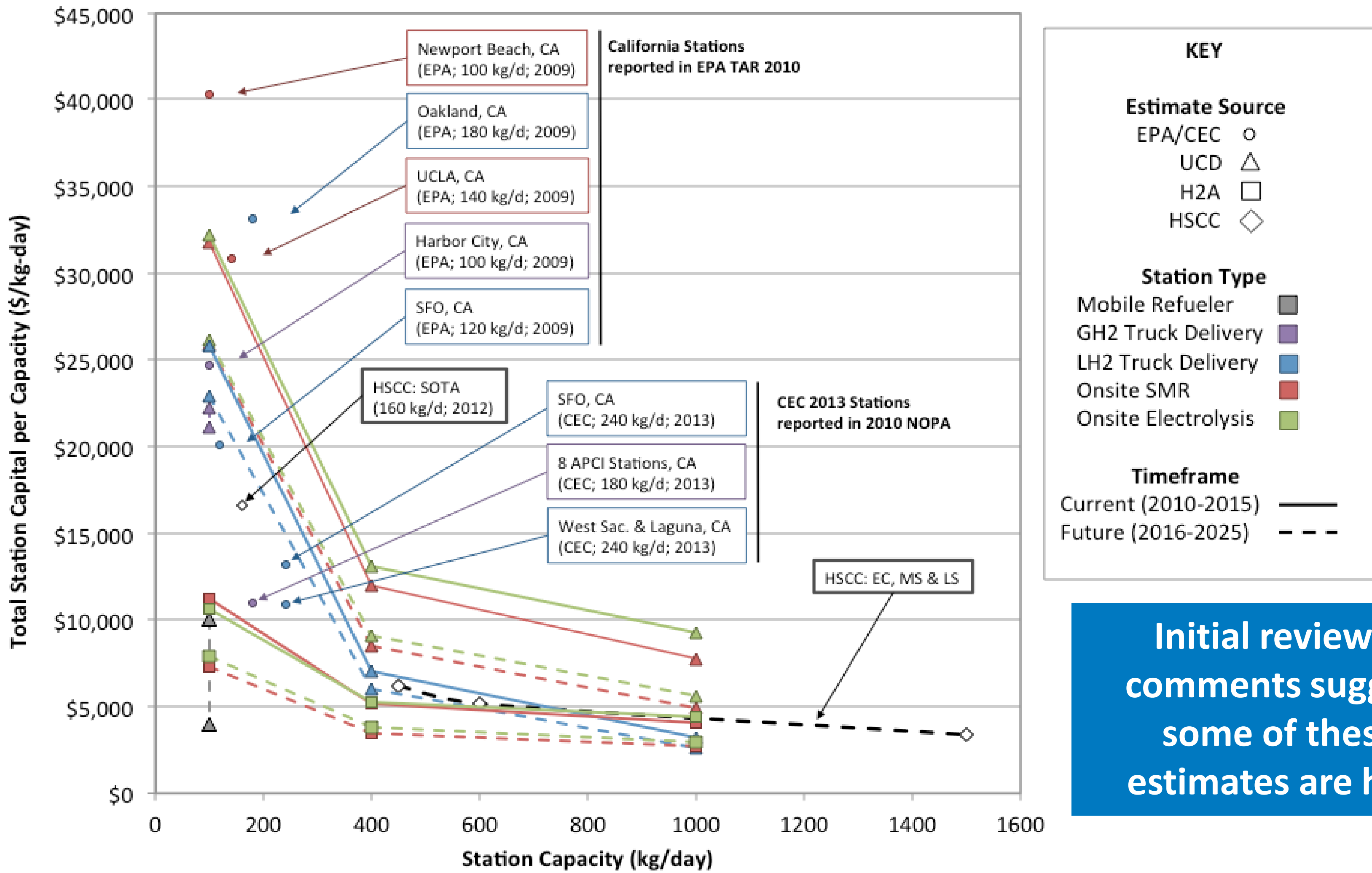
Capital costs per capacity for hydrogen stations over time: focus on larger, long-term stations



PRELIMINARY RESULTS

Final report expected to be published in late 2012 or early 2013.

Capital costs per capacity as a function of station capacity



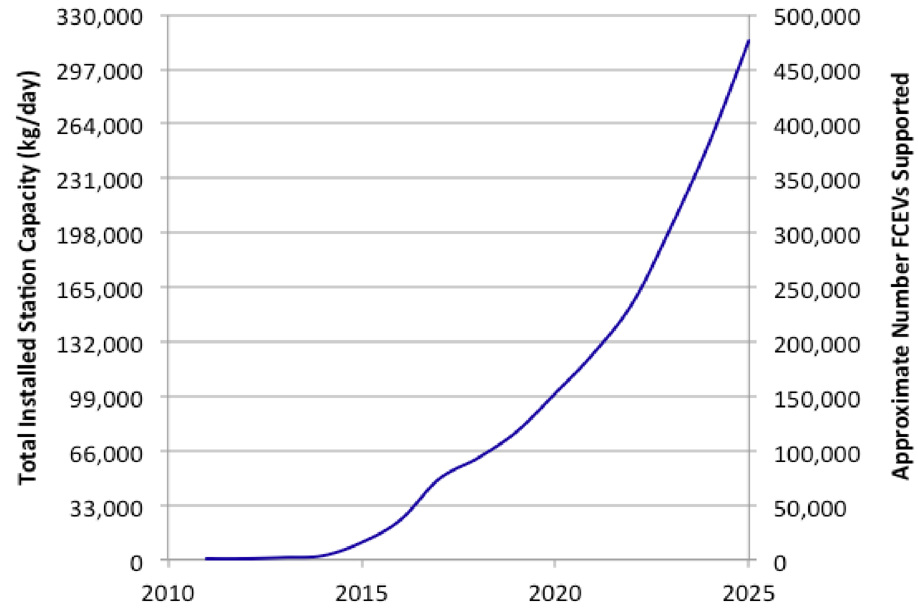
Initial reviewer comments suggest some of these estimates are high

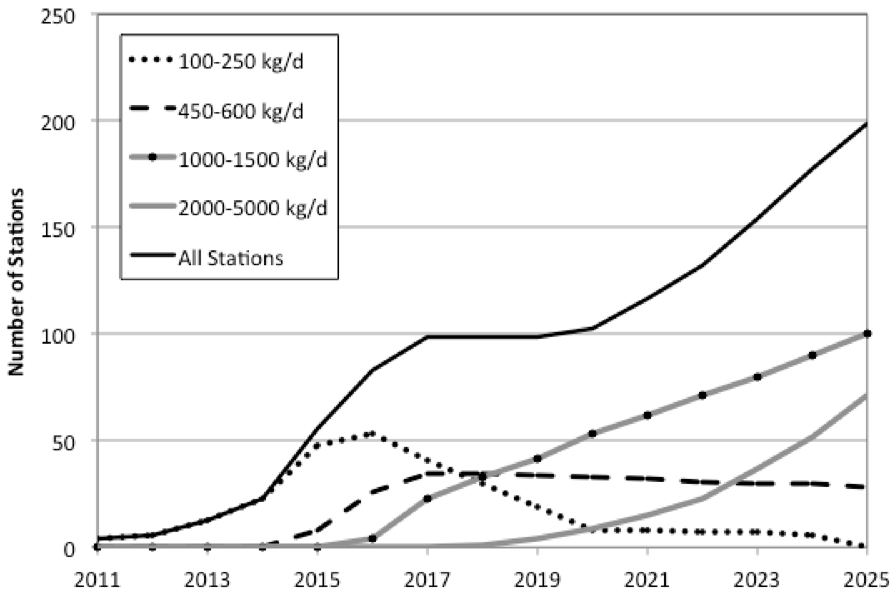
PRELIMINARY RESULTS

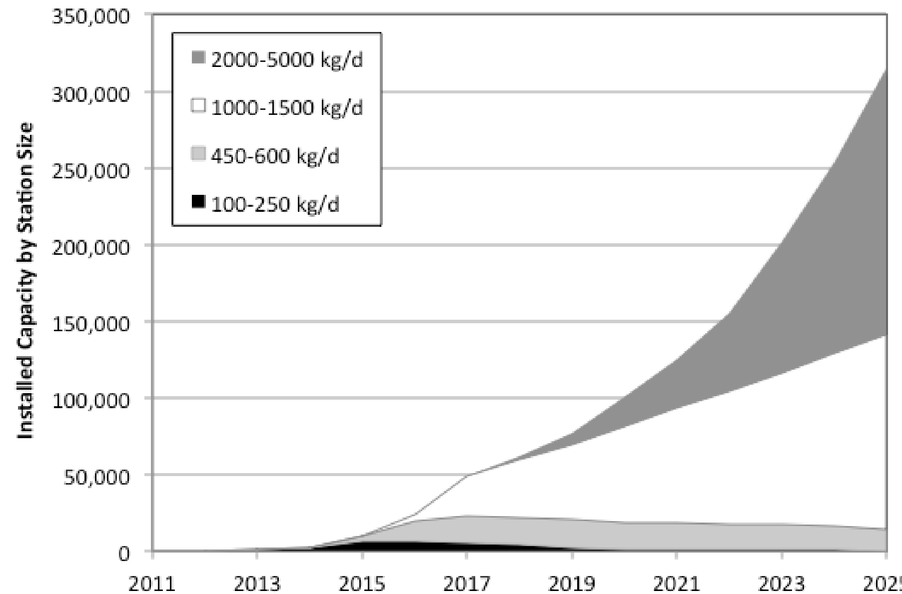
Final report expected to be published in late 2012 or early 2013.

California Case Study

- An aggressive national FCEV adoption scenario, starting in California, demonstrates how HSCC function evolves over time
- Relative station size function resolves coverage and economies of scale (Melaina and Bremson 2006)

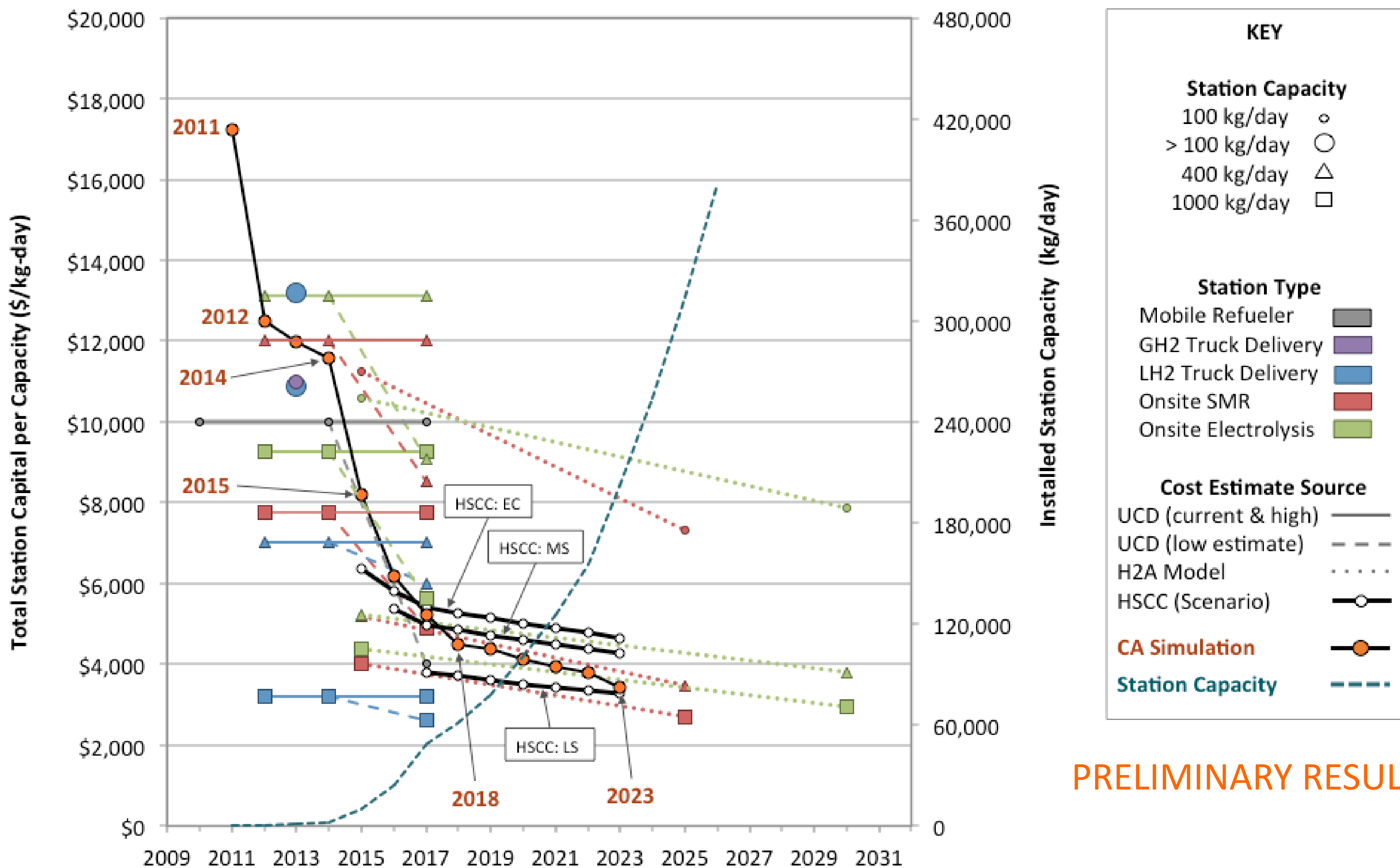






Number of stations deployed by station size (a) and total installed capacity by station size (b).

Reductions in station capital costs per capacity for the National scenario with California Early Market

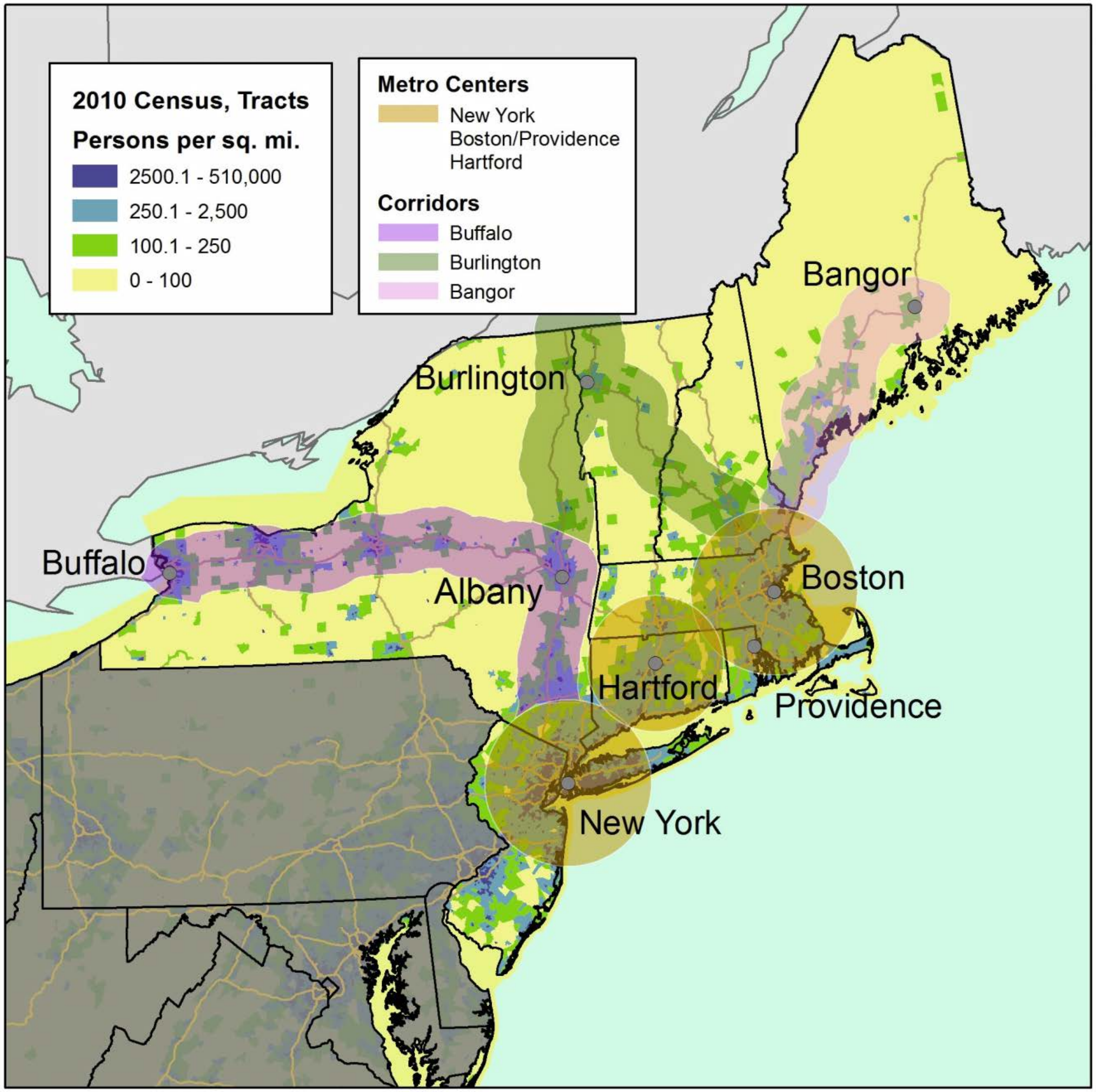


PRELIMINARY RESULTS

The CA Simulation curve is the HSCC function resolved for an expanding network of stations of different sizes (Q) and total installed capacity (V)

Applying HSCC results to Northeast Corridor (NEC)fuel cell vehicle deployment scenarios

- Two deployment scenarios have been developed for the NEC states based upon complying with the ZEV mandate
- Initial feedback has been received from engaged stakeholders
- The Connecticut Center for Advanced Technology (CCAT) has coordinated reviews of these preliminary results



FCV deployment scenarios meet ZEV mandate

36% ZEV Mandate Scenario

- Meets the ZEV mandate in the Northeast with 36% of credits between 2018 and 2025 derived from FCEV sales

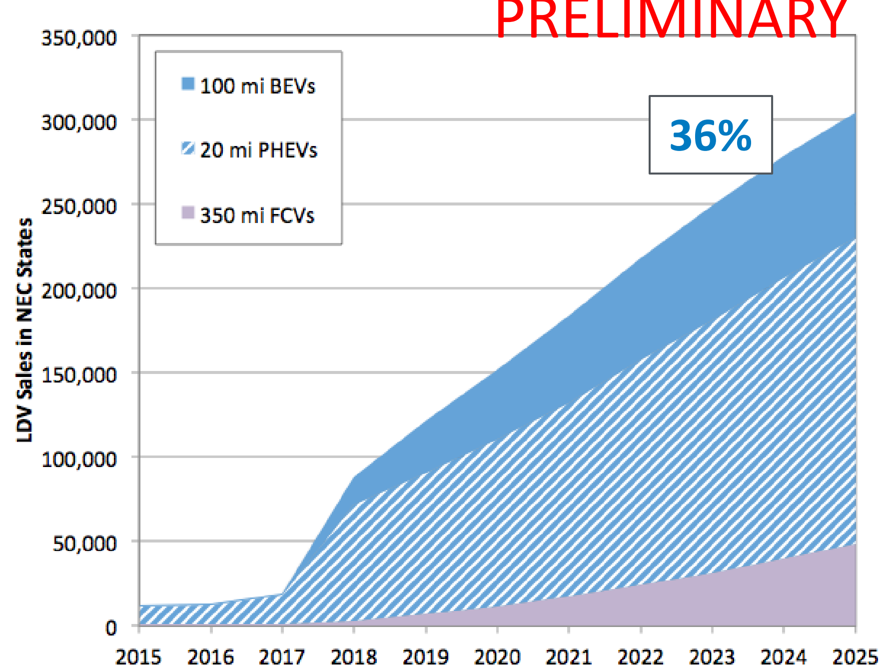
66% ZEV Mandate Scenario

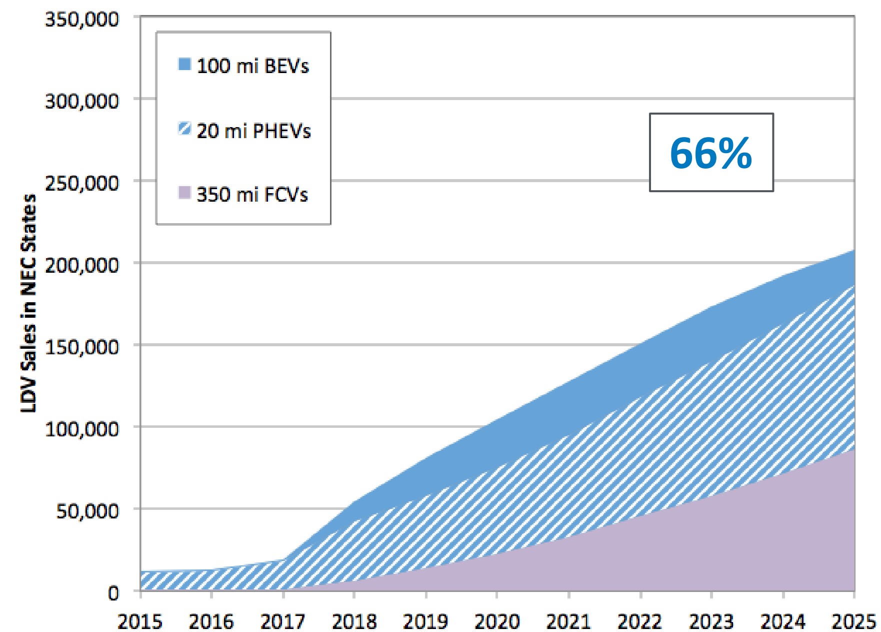
- Meets ZEV mandate with 66% of credits from FCEVs

Introduction of FCEVs is staggered similarly in both scenarios, starting with largest and highest density regions and eventually moving to markets along corridors

ZEV Credit Assumptions

- **350 mile FCEVs: 4.0**
- **100 mile BEVs: 1.5**
- **20 mile TZEV/PHEVs: 0.7**

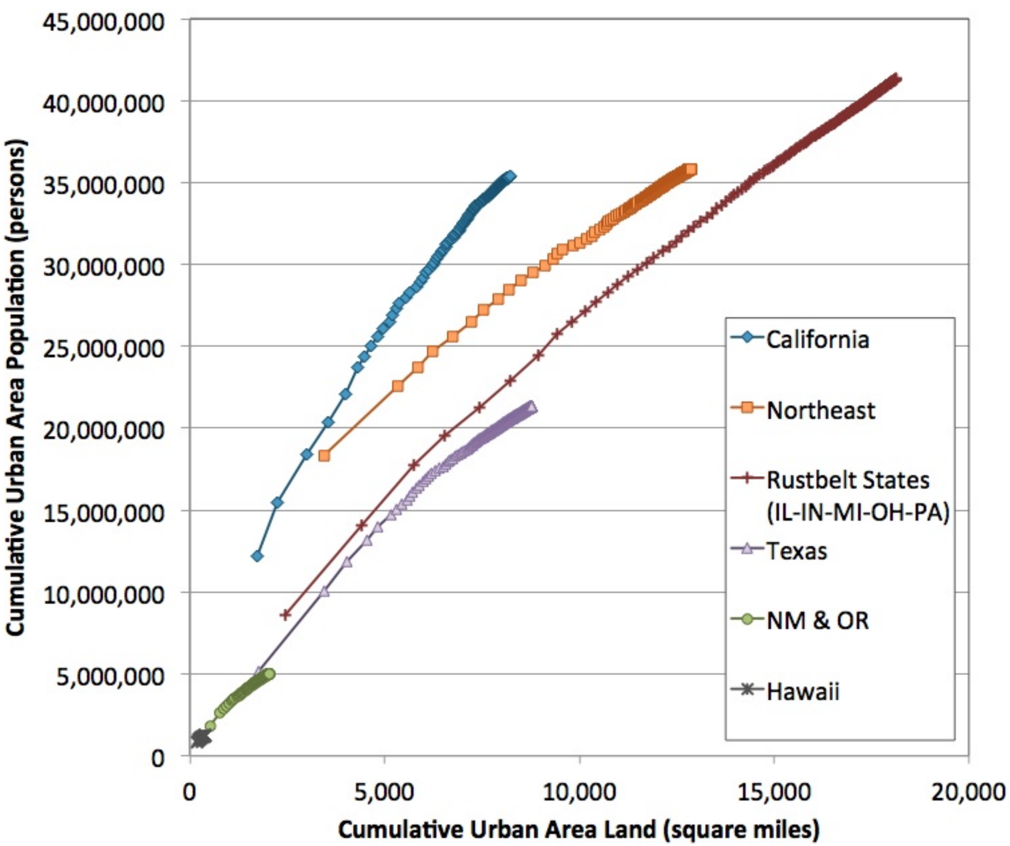


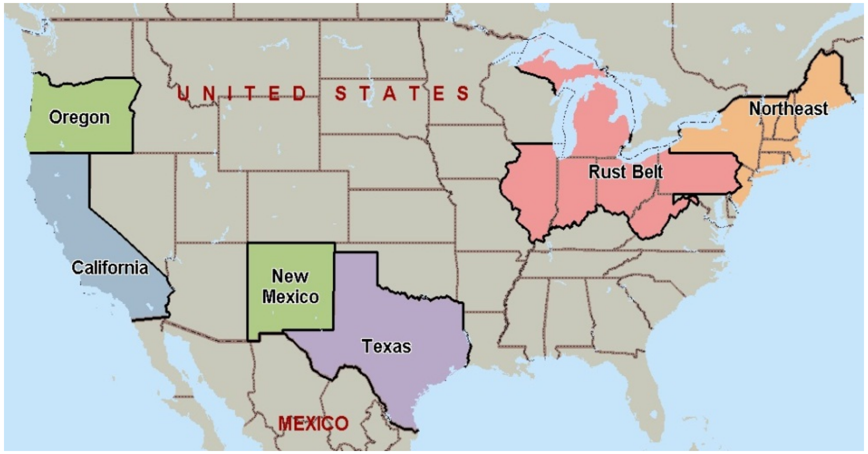


The CARB *ZEV Calculator* is posted here:
http://www.arb.ca.gov/msprog/clean_cars/clean_cars_ab1085/clean_cars_ab1085.htm

How does the NEC Compare to other U.S. regions?

- Cumulative urban area population vs. cumulative land area
- Northeast Corridor compared to other ZEV states (CA, OR, NM), Texas, Hawaii and Rust Belt States (IL, IN, MI, OH, PA)
- Cities in California contain more people within a smaller land area
  - CA: 35M within 8000 sq. mi.
  - NEC: 35M within 1,200 sq. mi.
  - ~50% more land area/person

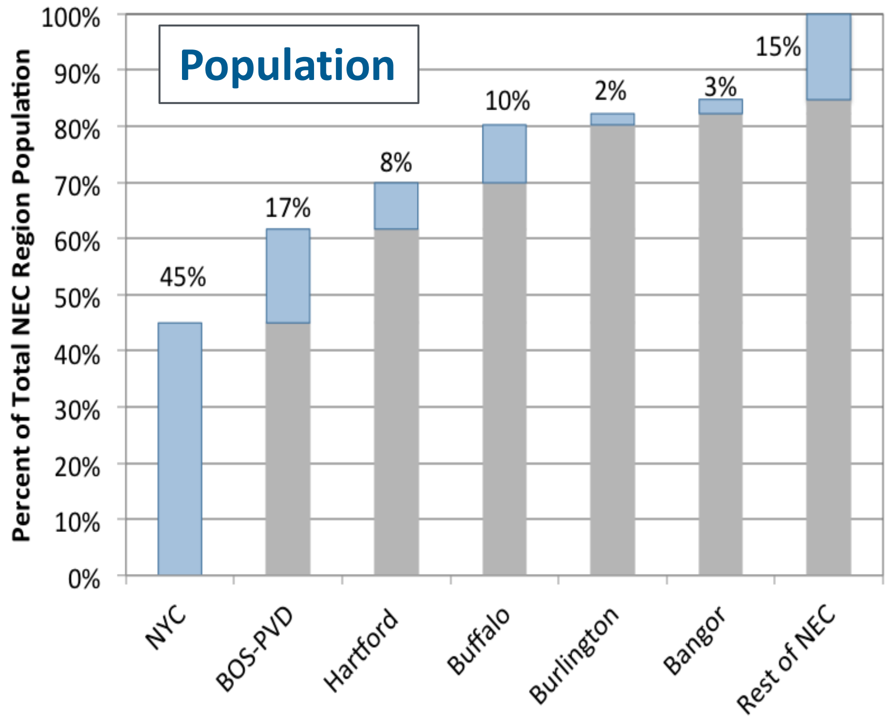




This figure only indicates population within Census Urban Areas – not the total regional population

Census Population and an Early Adopter Metric

- Metro regions (NYC, BOS-PVD, Hartford) are ~70% of NEC Population and ~14% of land area
- An *Early Adopter Metric* (EAM) is proposed as a means of demonstrating potential clustering patterns (Ogden and Nicholas 2011)
- Other metrics are used to propose station placement and network expansion patterns



$$EAM = \alpha \frac{HEV\ sales}{square\ mile} + \beta \frac{Luxury\ Vehicle\ Sales}{square\ mile} + \gamma \frac{High\ Income\ Households}{square\ mile}$$

Values for α, β, and γ are developed to produce weights of 50%, 25% and 25% for each attribute.

Hybrid electric vehicle sales	Vehicles per square mile sold in 2011, by zip code.
Luxury vehicle sales	Vehicles per square mile sold in 2011, by zip code.
High income households	Households with greater than $100,000 income per sq. mi., by census tract and with 2010 census data.

EAM Results for L.A. compared to CaFCP Roadmap Clusters

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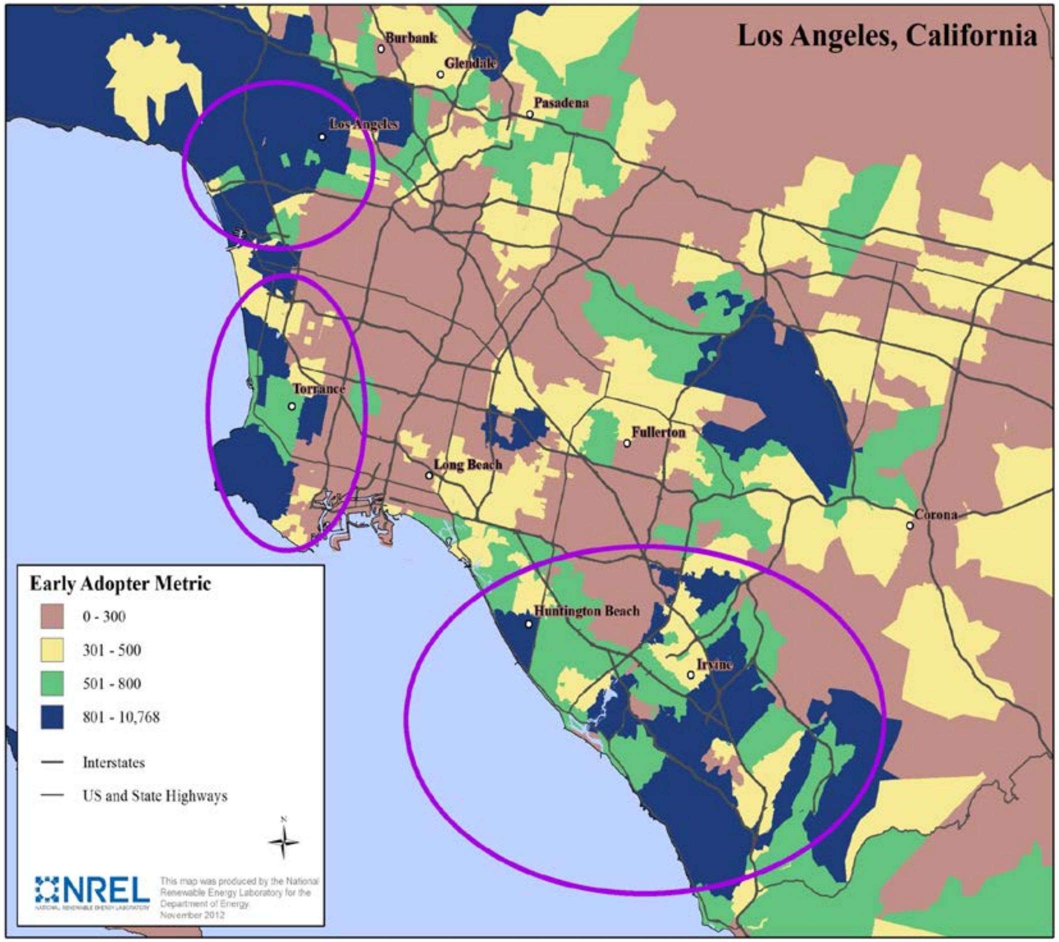
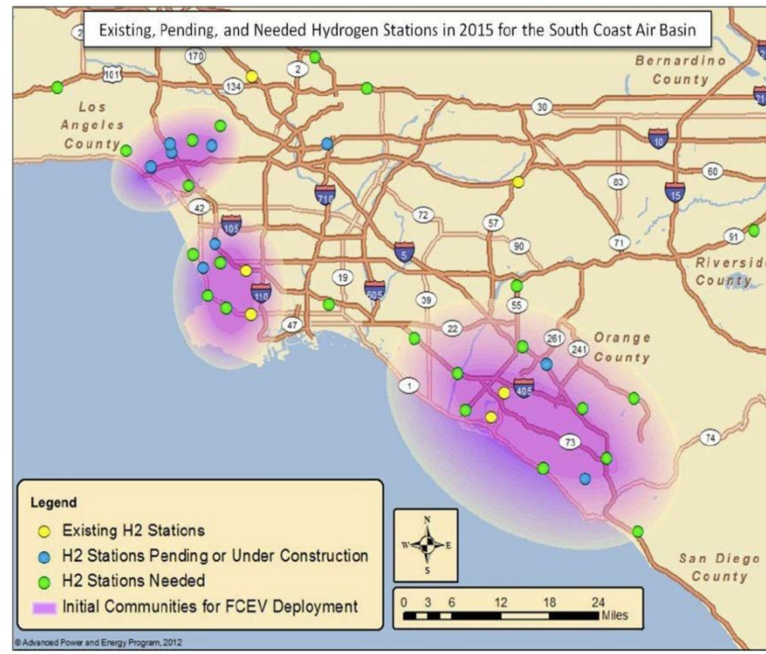


Station placements and clusters below are from the CaFCP Roadmap, and rely upon results from the UC Irvine STREET model.



A California Road Map: The Commercialization of Hydrogen Fuel Cell Vehicles, California Fuel Cell Partnership, June 2012, available at http://cafcp.org/roadmap

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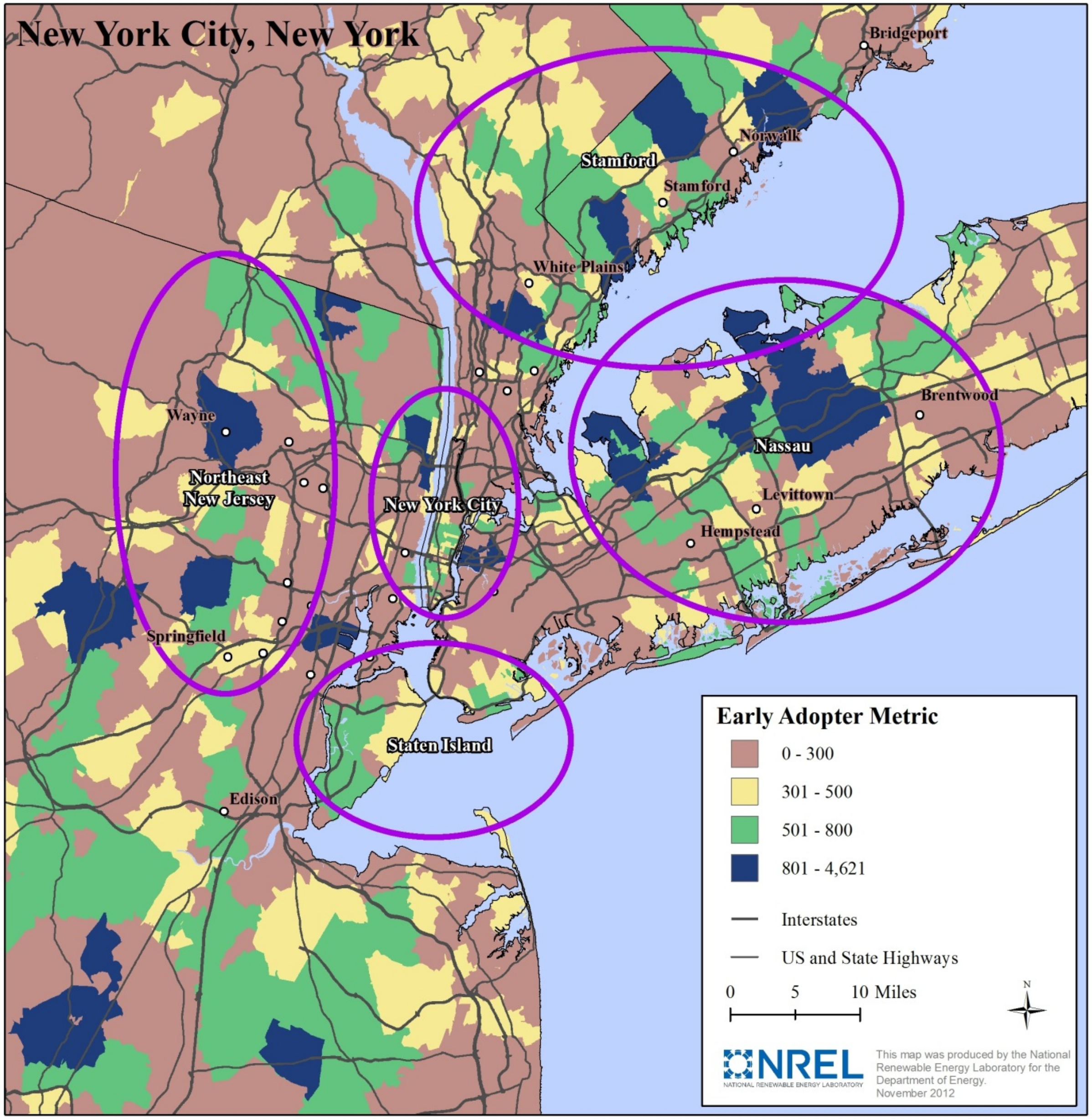
EAM Results and Potential Clusters for the NYC Region



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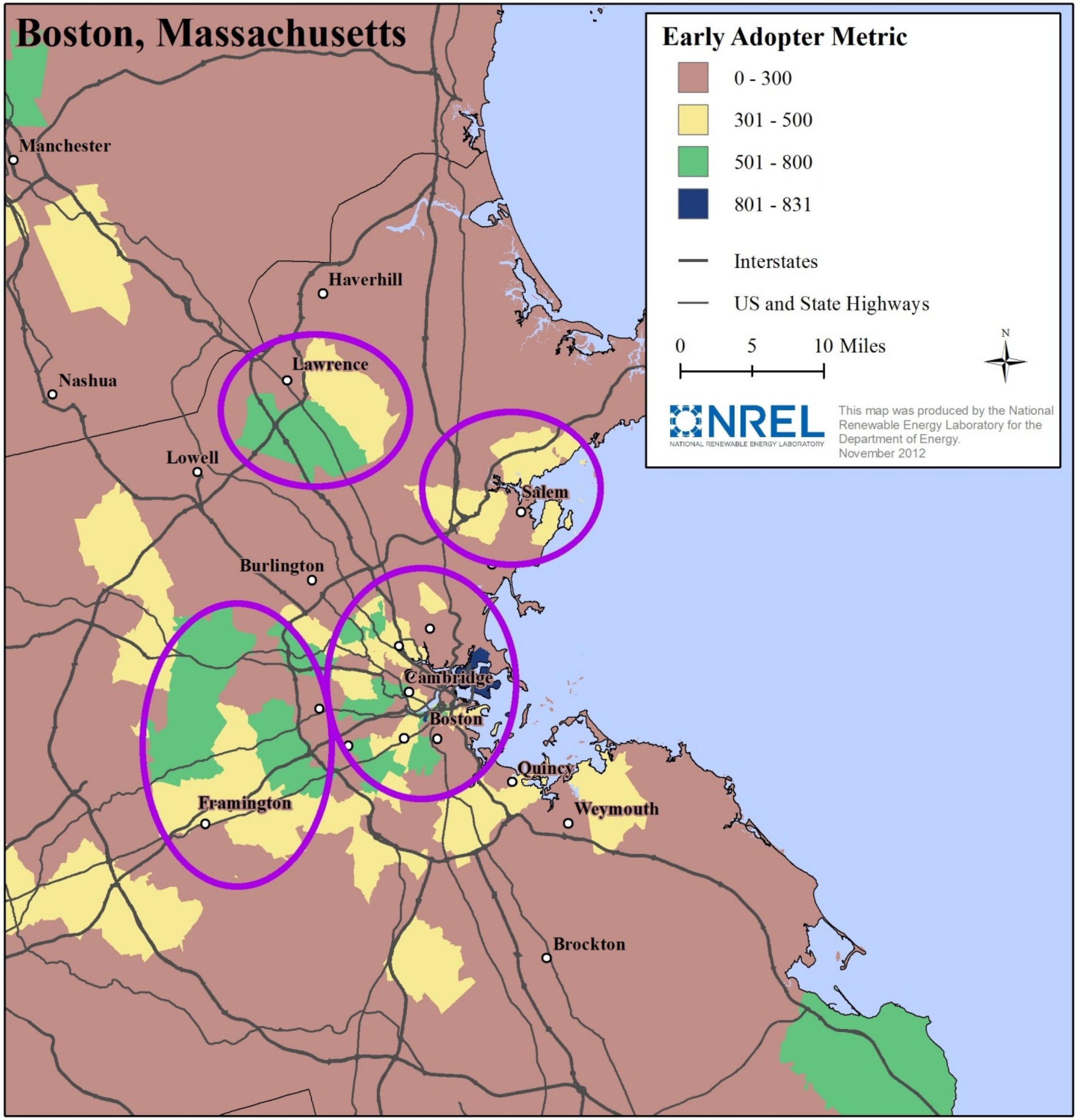
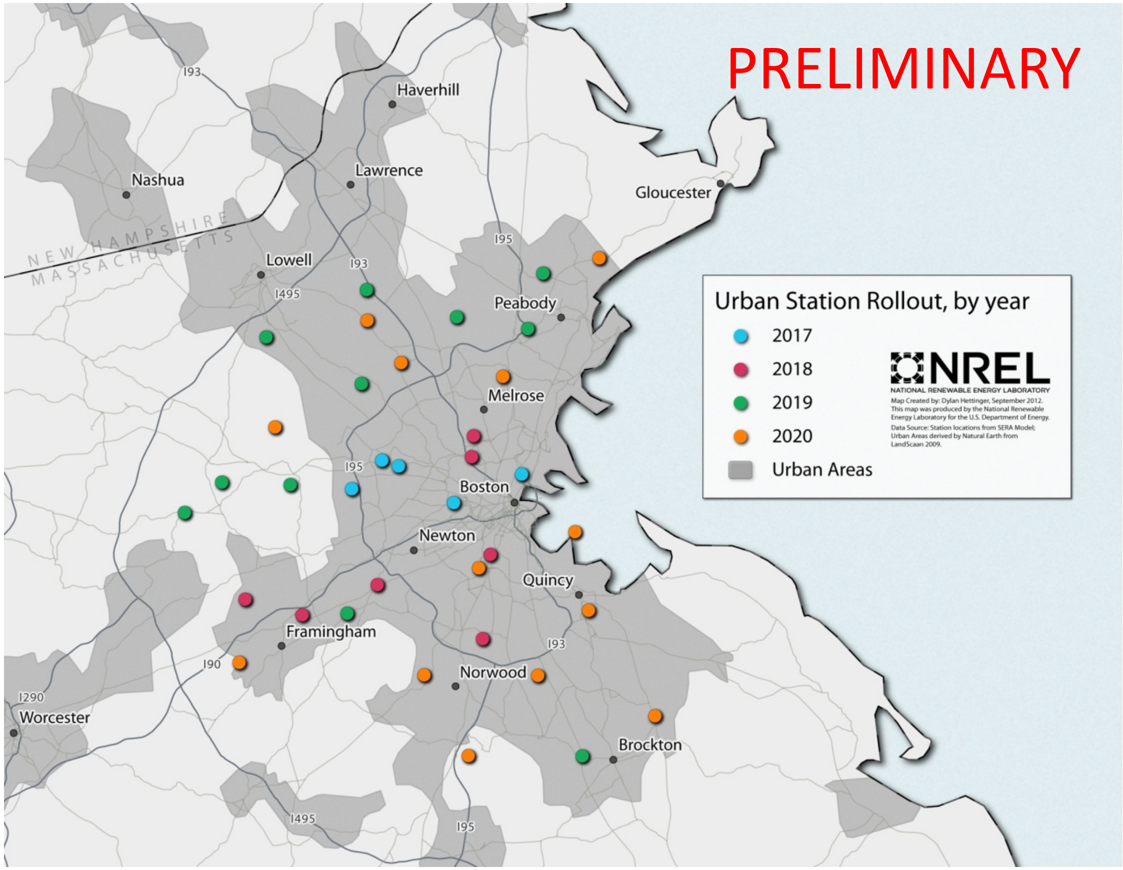
EAM Results and Potential Clusters for the Boston urban area



Station Clustering for Early Adopters

- **Recent model enhancements include endogenous generation of "clusters" within urban areas**
  - The goal is not to replace good planning, but to capture benefits of clustering
  - Example results for first 36 stations in Boston region are shown below
- **Placements based upon:**
  - HEV sales by Zip Code
  - Household incomes
  - Density of existing gasoline stations
  - Proximity to interstates
  - Sequential coverage
- **The ADOPT Consumer Choice model is being integrated into SERA**
  - More consumer-focused clusters at Zip Code level



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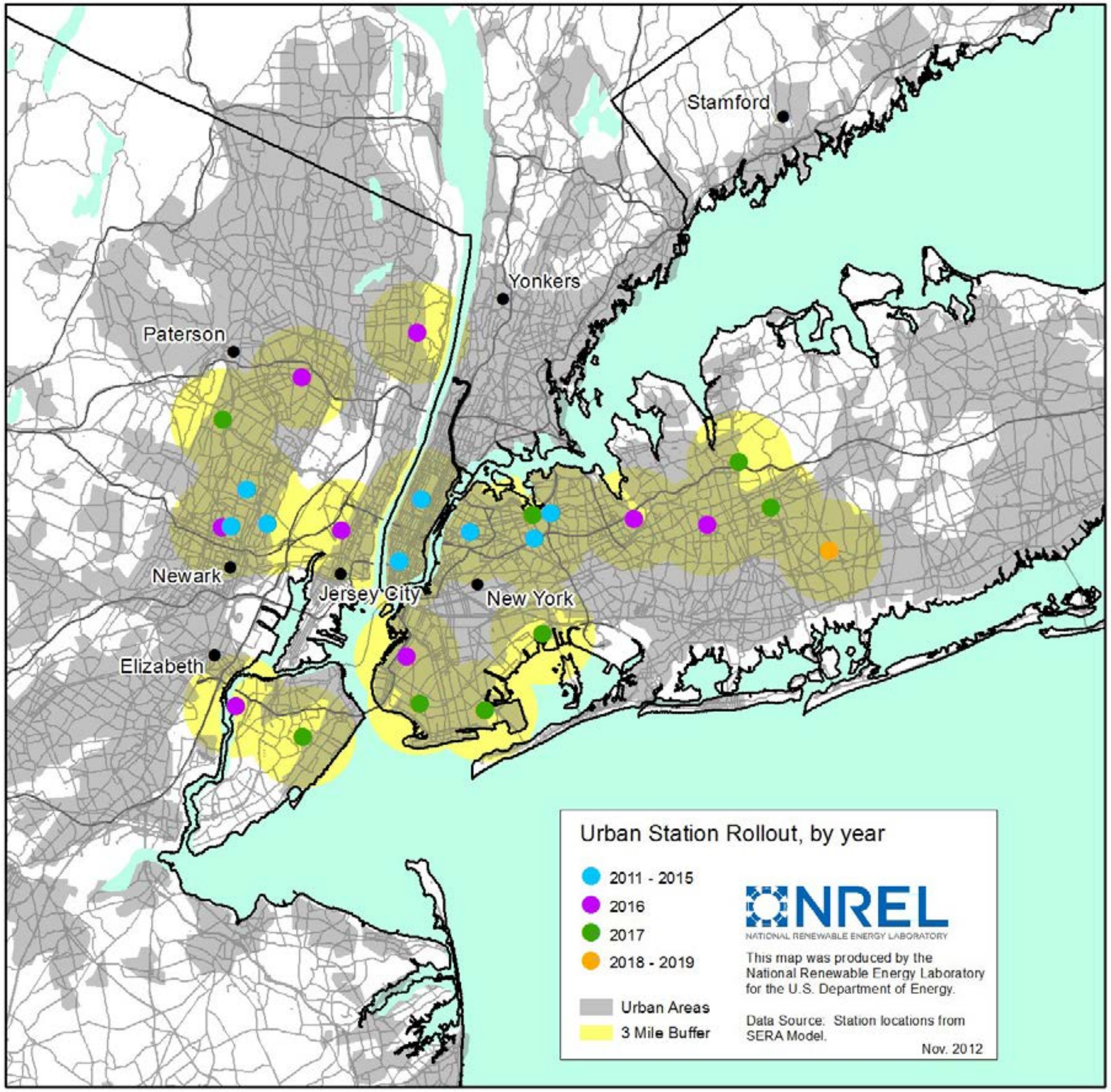
Algorithm results for NYC Region: first 25 stations

<u>**3-mile Buffers**</u>

Correspond to approximately 5-7 minute travel time to the station (assuming an average speed of 25-35 mph).

These proposed locations can be refined with additional stakeholder input.



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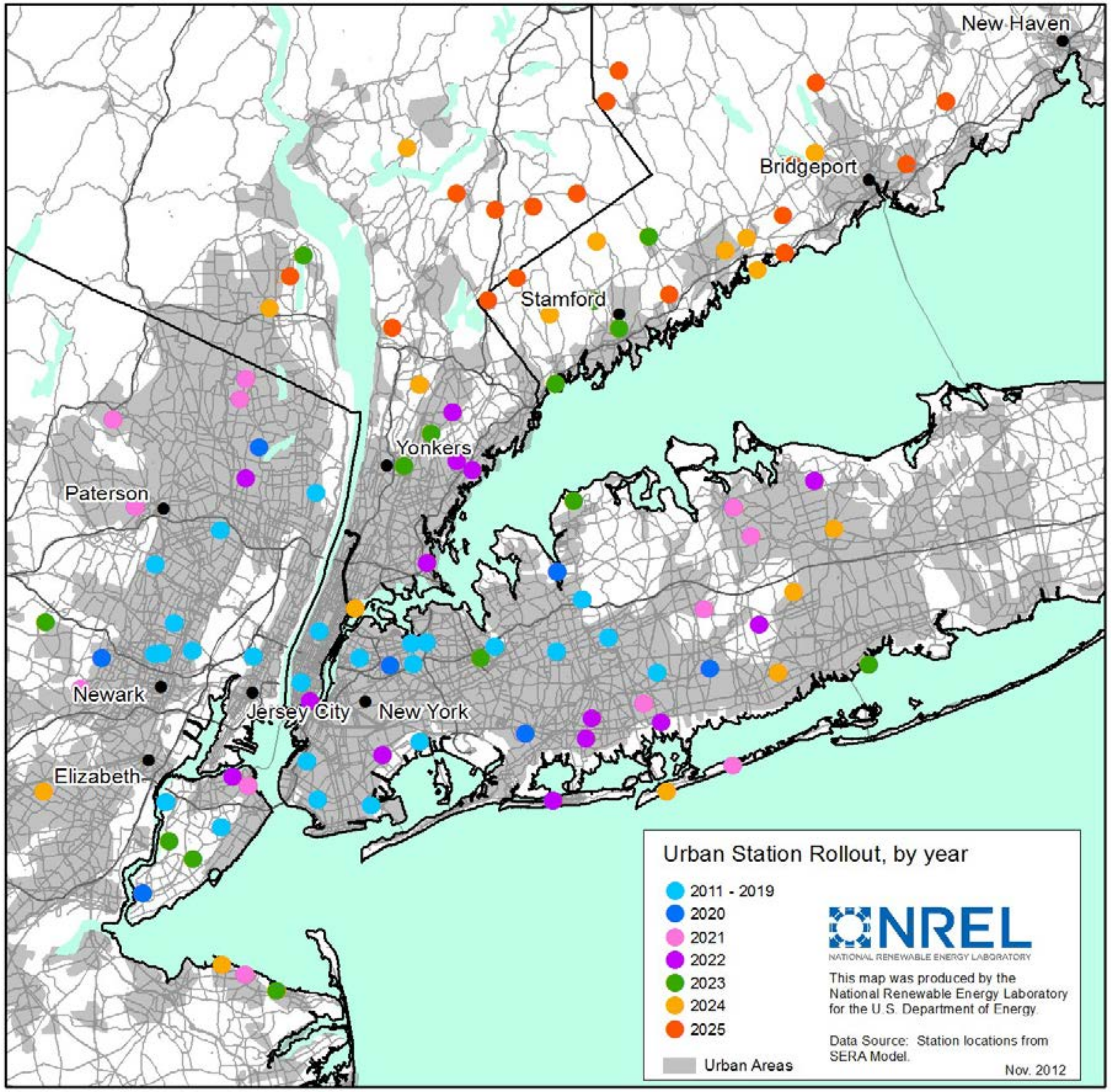
Proposed NYC Region stations out to 2025



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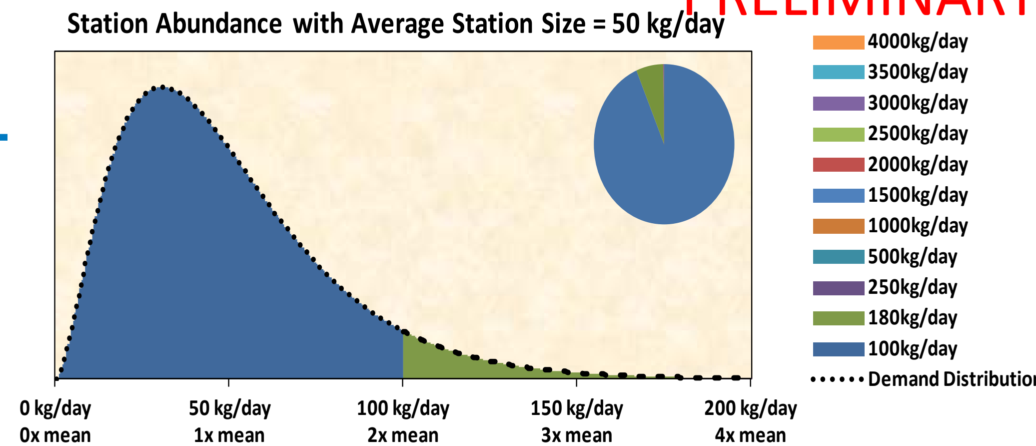
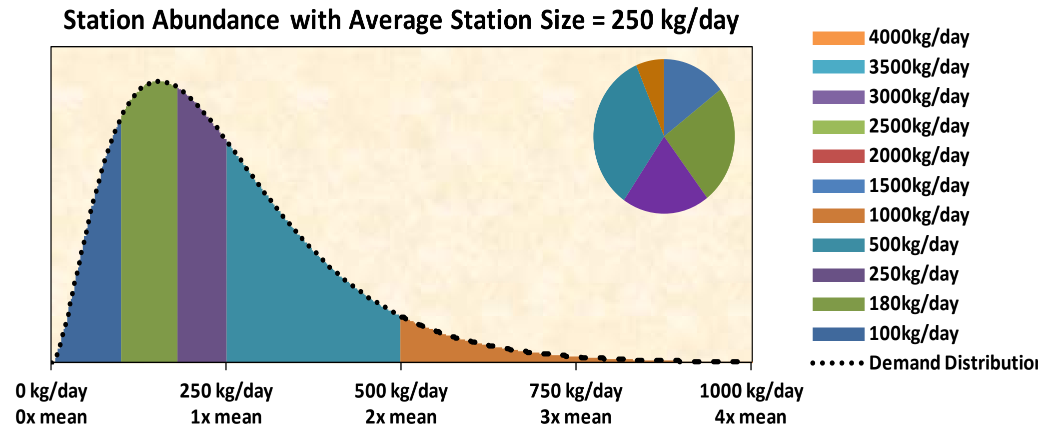
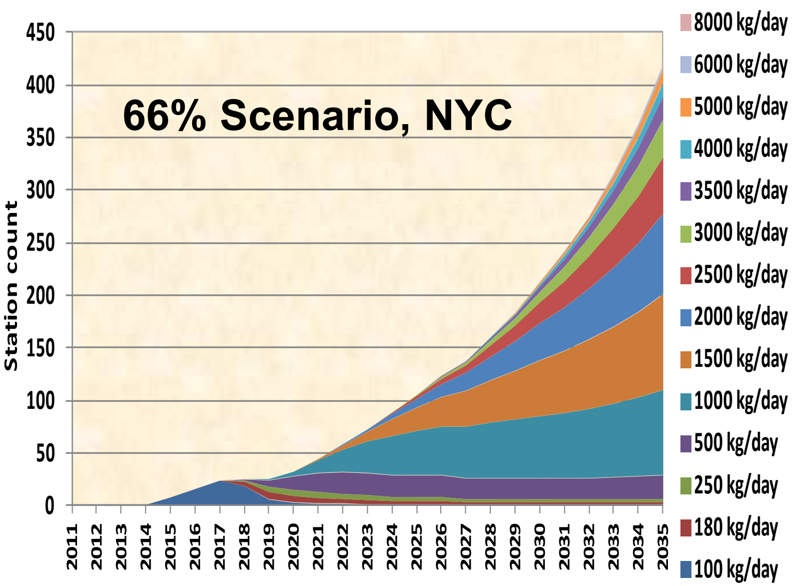
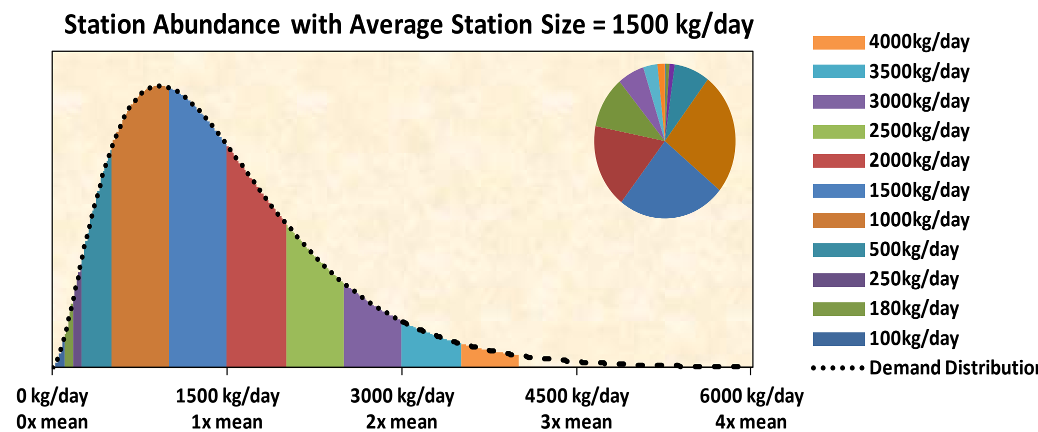
Distribution of station sizes

Larger stations are introduced while keeping a relative size distribution that maintains coverage and simulates competition









Solver determines financing need

Three financial objective are met each year

1. Cash on hand (1 month hydrogen feedstock)
2. Return on equity (10%; maintained with production incentives)
3. Debt to equity ratio (ceiling of 0.5)

These objectives are met by resolving three metrics:

1. Required revenues. Shortfalls from market prices are made up with incentives
2. New financing (debt and equity)
3. Split of debt and equity (to maintain minimum ratio)

Hydrogen price ceiling ($/kg) is equivalent $/mile vs. gasoline

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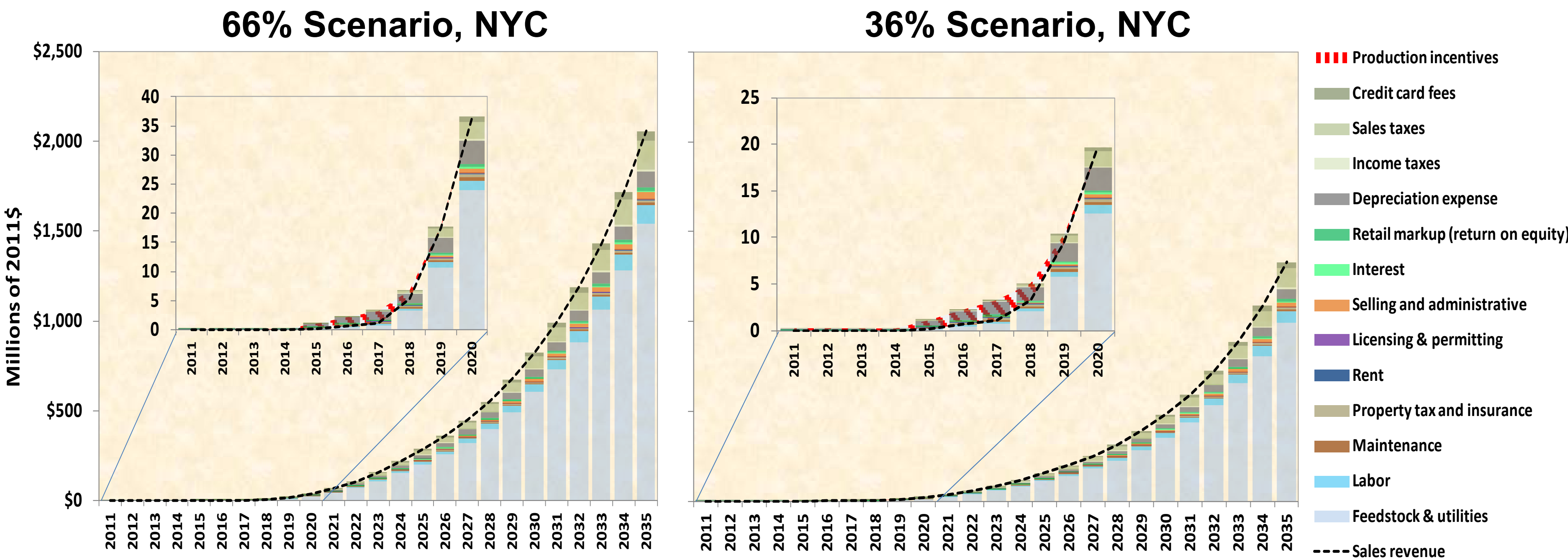
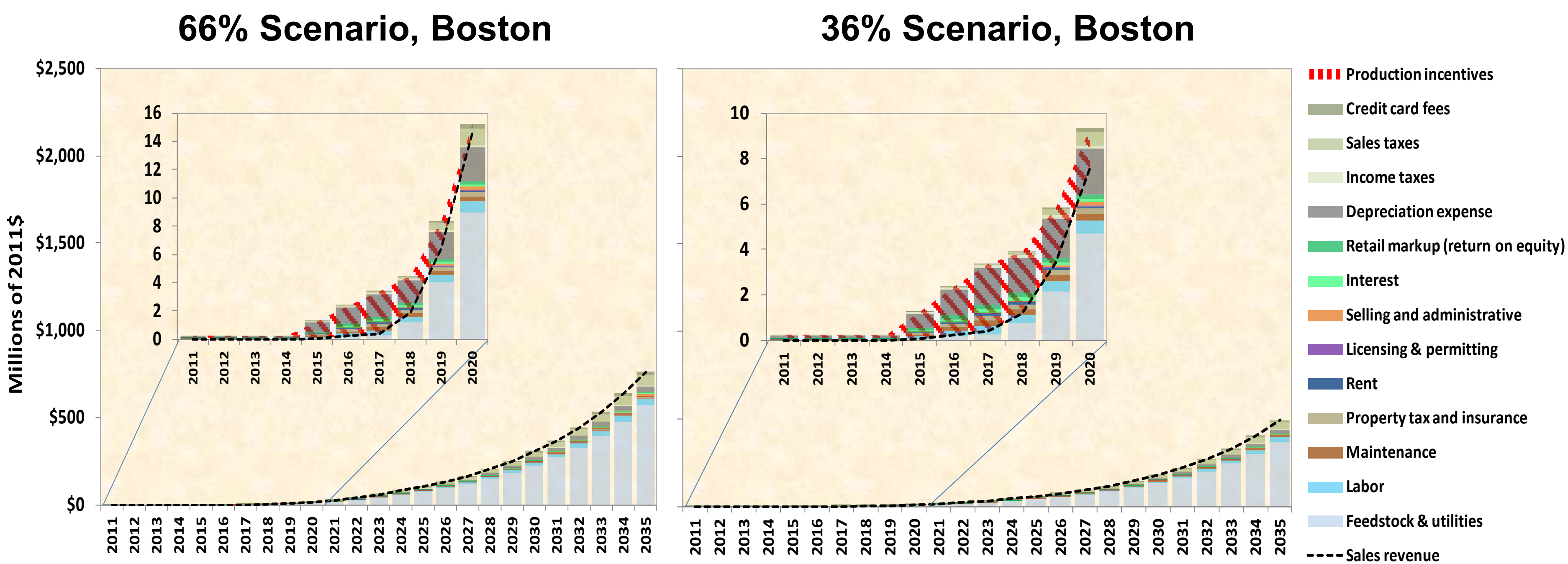
Cash flow results with incentives: NYC



Cash flow results with incentives: Boston



Cash flow results with incentives: Hartford

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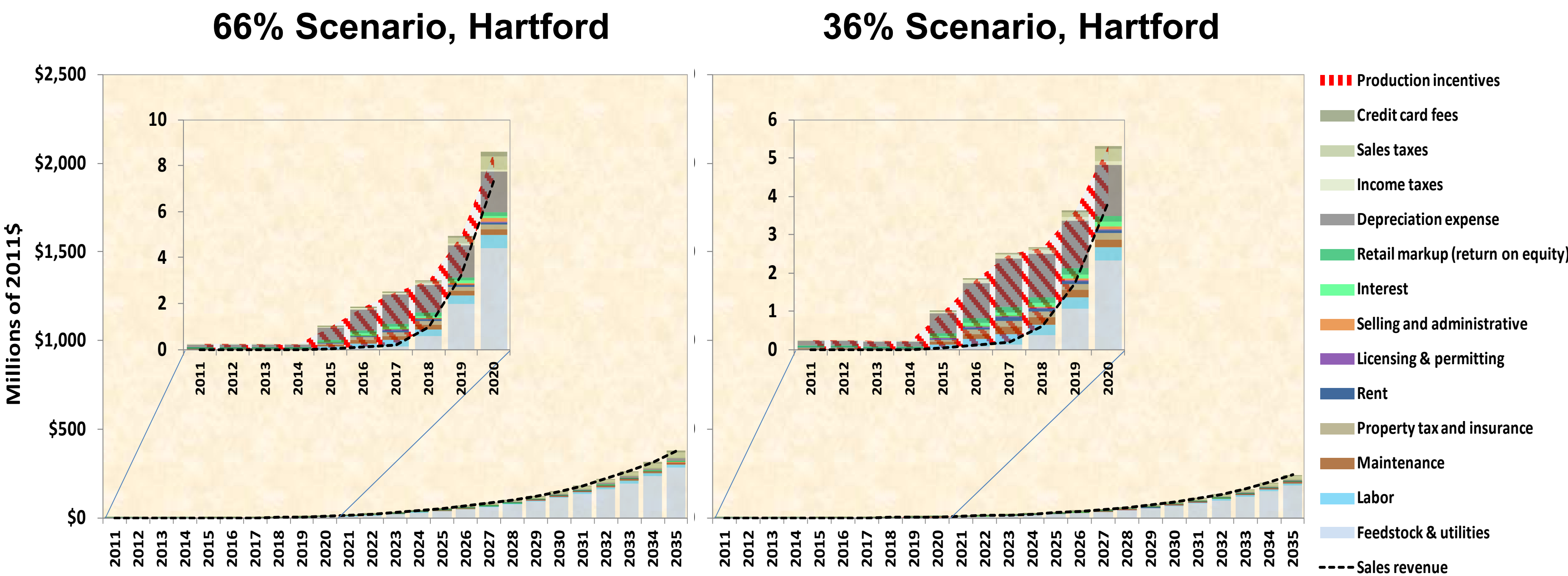

Cash flow by source resolved for three metro areas

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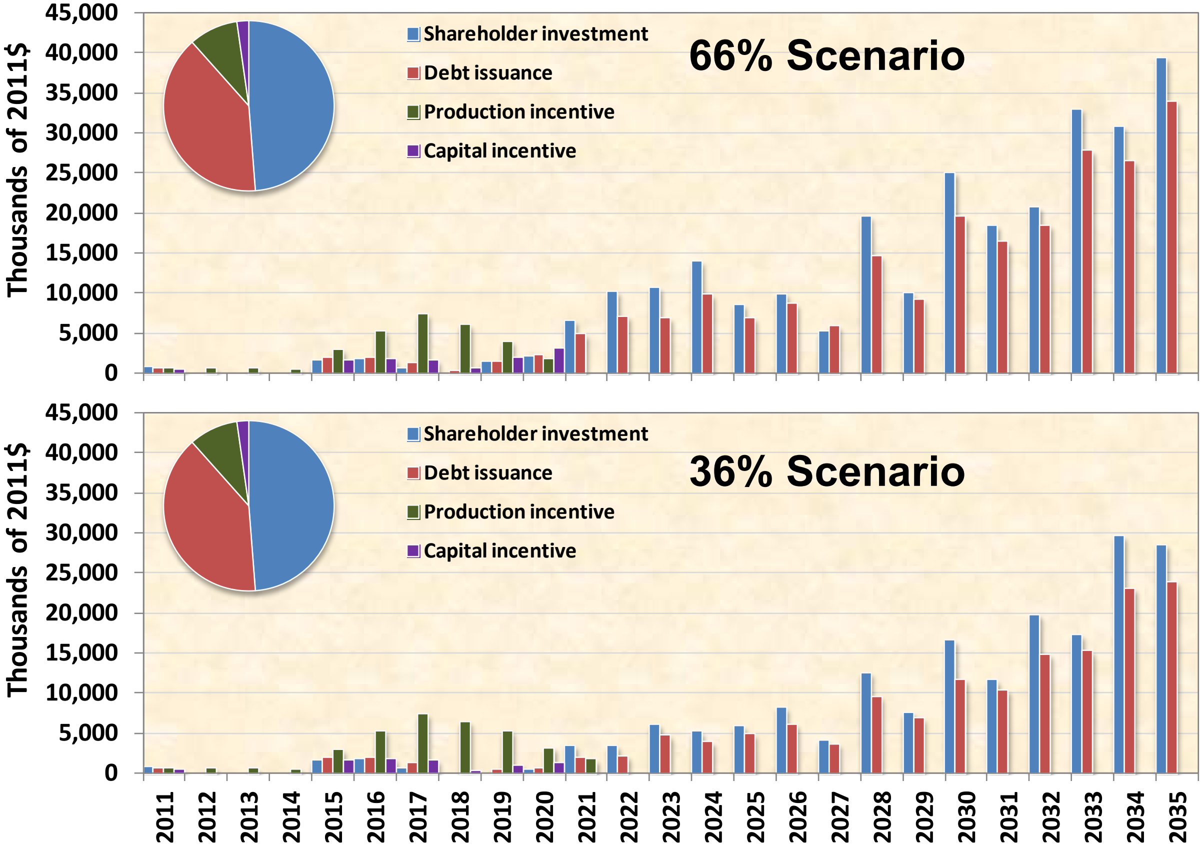
Note these are likely the larger and more profitable markets.

A more complete analysis of the NEC, including corridors and additional urban areas, will involve profits from these metro areas covering costs to build inertia in new markets.

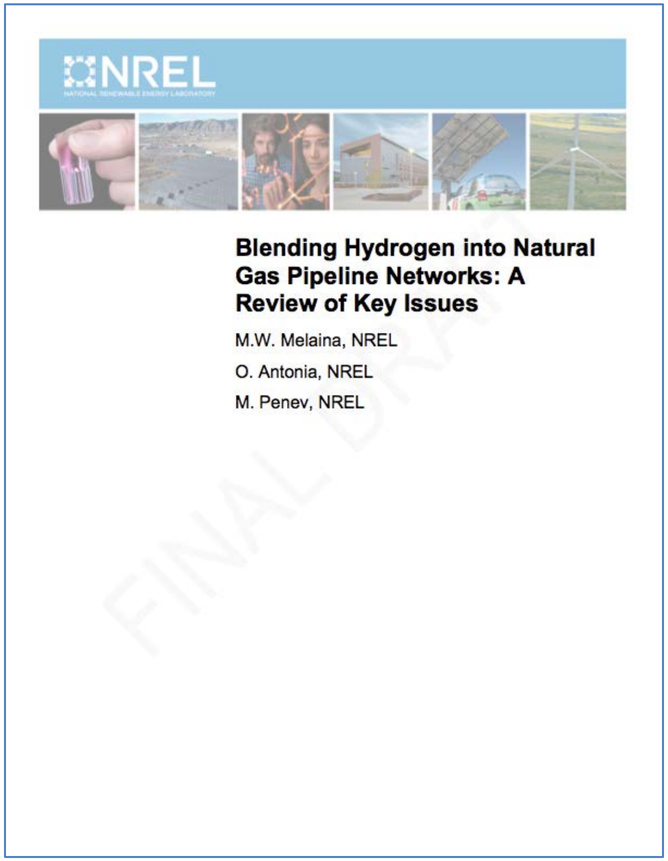


Blending Hydrogen into Natural Gas Pipelines

Overview: Hydrogen in Natural Gas Pipelines

- The report is in a final review stage
- The report includes a 70 page appendix by the Gas Technology Institute (GTI) reviewing key issues and assessing safety issues associated with blending in the U.S. natural gas pipeline system
- Major topics reviewed in both the body and GTI appendix include:

  1. ***Benefits of blending***
  2. ***Extent of the U.S. natural gas pipeline network***
  3. ***Impact on end-use systems***
  4. ***Safety***
  5. ***Material durability and integrity management***
  6. ***Leakage***
  7. ***Downstream extraction***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Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues

M.W. Melaina, NREL

O. Antonia, NREL

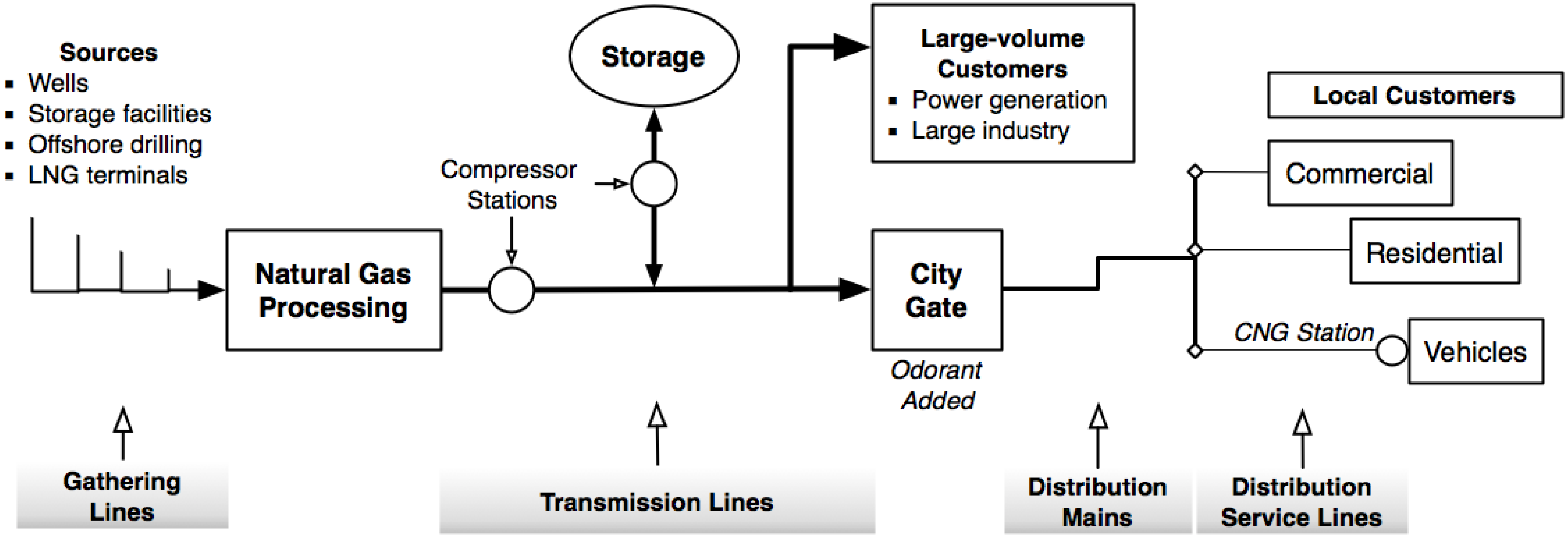
M. Penev, NREL

FINAL DRAFT

Most of the report is a review of existing literature. NREL staff added some novel cost analysis on downstream extraction.

How would it work? Is anyone trying this?

Schematic of the Natural Gas Pipeline System



- Hydrogen could be injected at various points upstream
- It may be economically viable to extract at the city gate or elsewhere
- Low levels of hydrogen can be combusted along with methane
- E.ON and Hydrogenics have engaged in a "Power-to-Gas" project in northeast Germany*

*http://www.eon.com/en/media/news/press-releases/2011/11/11/e-dot-on-examines-options-for-storing-wind-power-in-the-german-gas-grid.html# ; http://www.hydrogenics.com/invest/News_Details.asp?RELEASEID=678878

Benefits of Blending

- **Lower Carbon Emissions for Natural Gas**
  Blending hydrogen produced from low-carbon energy sources (renewables, nuclear or fossil with carbon capture and storage) would reduce the overall greenhouse gas (GHG) emissions associated with the natural gas blend product.
- **Sustainable Transportation Fuel**
  Hydrogen can be injected upstream and extracted downstream (e.g., at the city gate) for use in fuel cell electric vehicles, resulting in lower criteria emissions, petroleum reductions, and potentially lower GHG emissions (depending upon the source of the hydrogen).
- **Transport and storage of renewable hydrogen**
  If implemented under economically favorable conditions, blending can tap into otherwise stranded renewable resources by providing a means of both storing and transporting renewable hydrogen. This benefit would be viable only if alternative means of delivering renewable energy/hydrogen are more costly or more difficult to implement.

Extent of the U.S. Natural Gas Pipeline Network

- The U.S. natural gas pipeline is extensive, including 2.44 million miles of pipeline and ~400 underground storage facilities.
- City Gate facilities are numerous, with several typically being located near major urban areas where transmission lines drop in pressure to feed natural gas into local distribution systems.
- How many city gate facilities are there in the United States? Data is not widely available, but estimates can be made from the EPA GHG report:

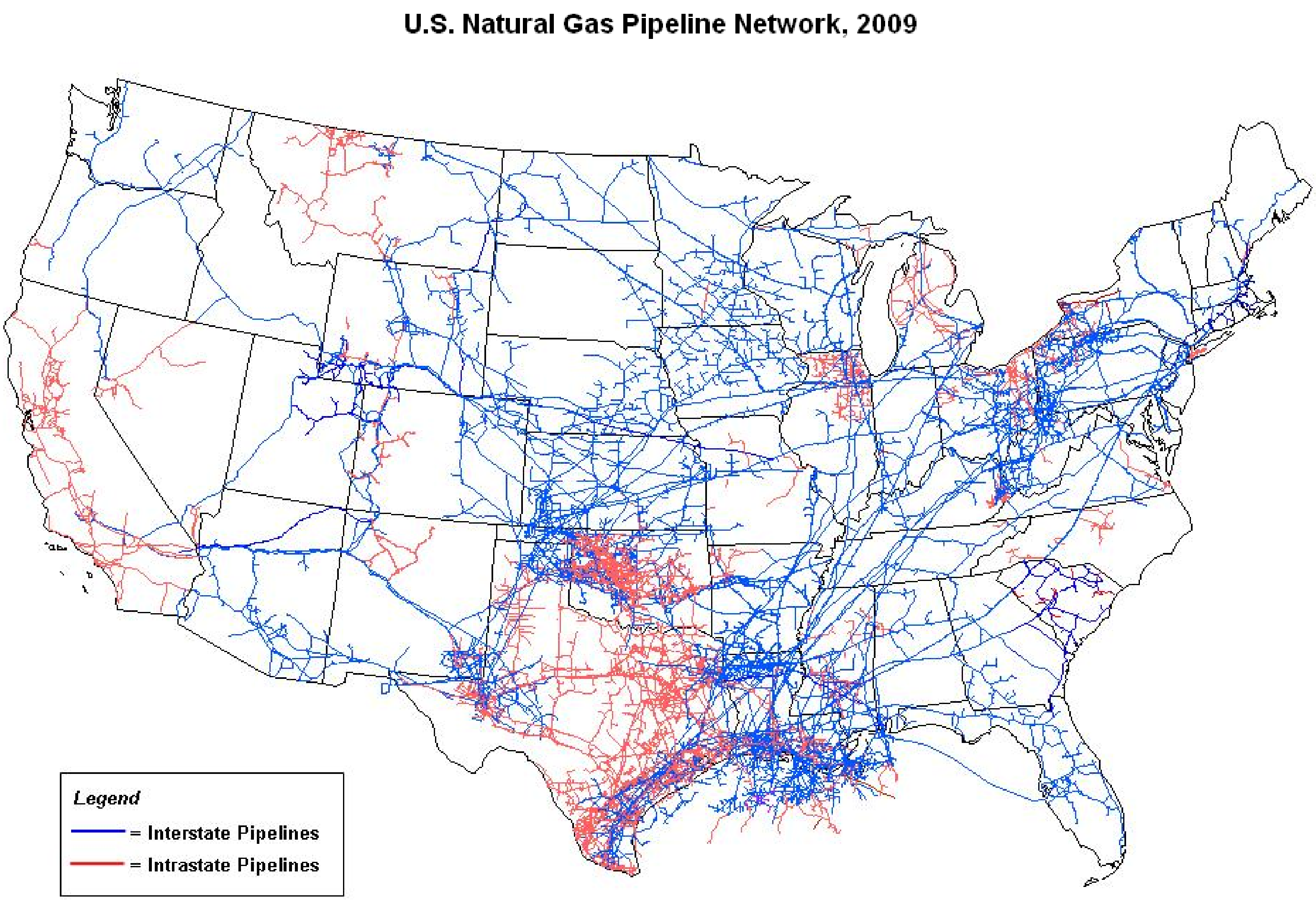
<u>EPA GHG Inventory estimates for city gate stations in 2011</u>

Inlet pressure (psig)	# Stations*
>300	11,200 - 14,800
100-300	56,700 – 34,600

- The rise of shale gas is changing the landscape of pipeline distribution, and will continue to do so as production share increases.

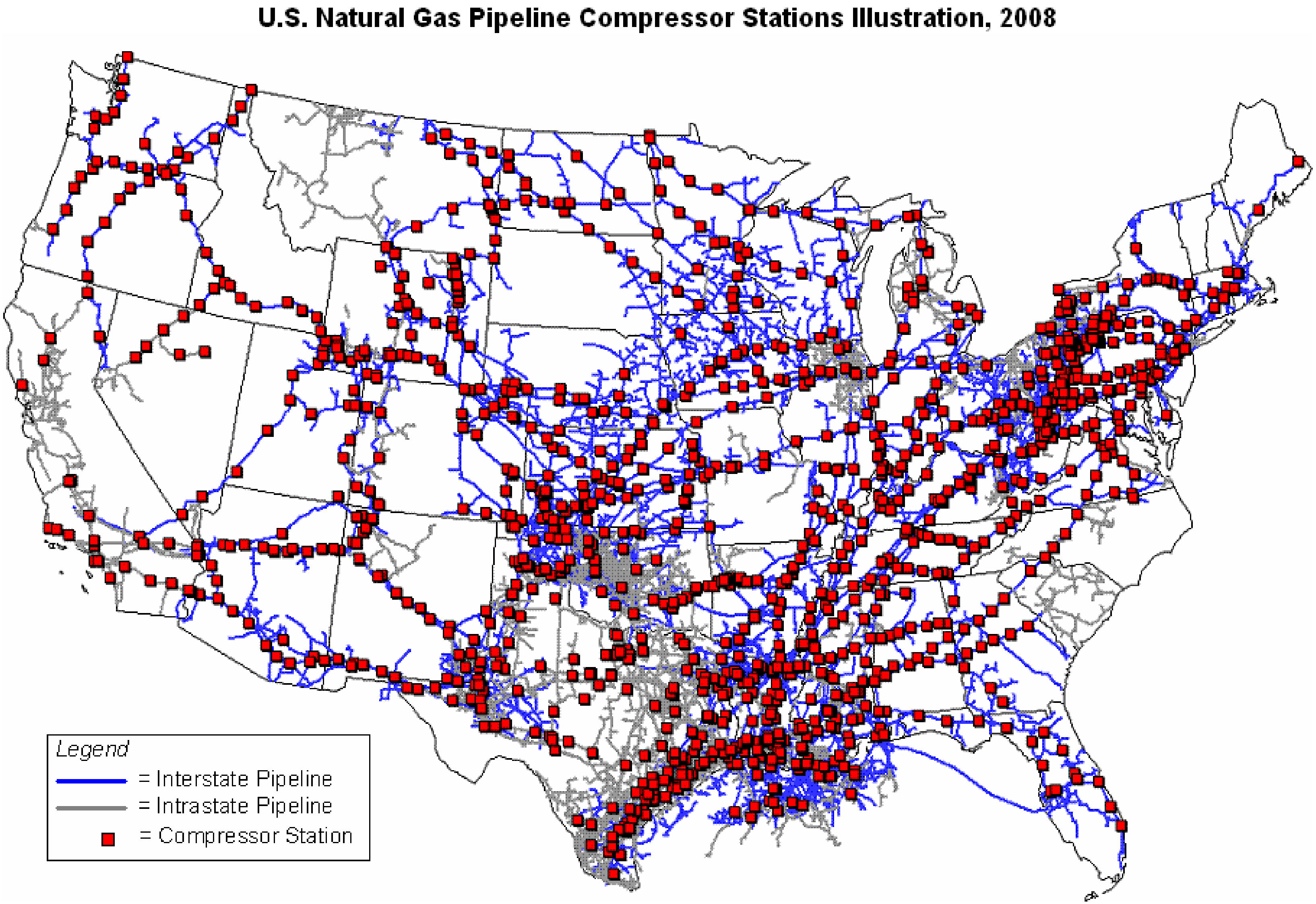
* Low ranges, used in the EPA GHG report, are based upon ratios of stations per gas consumption in 1992 and 2010. High ranges, developed for this report, are based upon ratios of stations to distribution main miles in 2011 and 1992 (Campbell and Stapper 1996; EPA 2012).

Extent of the U.S. Natural Gas Pipeline Network

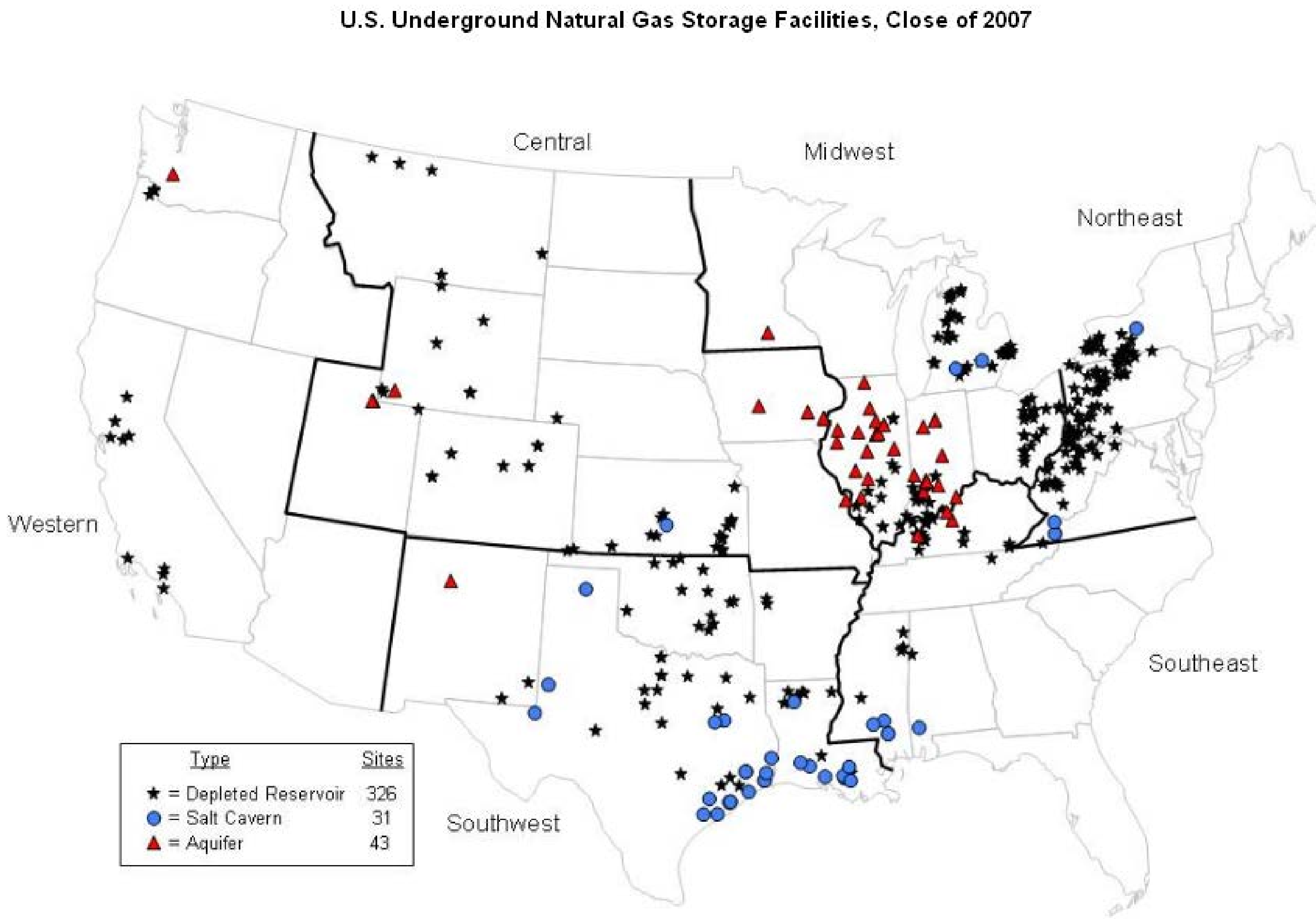


Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Extent of the U.S. Natural Gas Pipeline Network



Extent of the U.S. Natural Gas Pipeline Network



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

Impact on End-use Systems

- With properly maintain appliances, hydrogen blends up to 28% may be acceptable from a safety perspective (De Vries et al. 2009)
- Hydrogen blends at even low levels, however, can be a problem for appliances that are not properly maintained (Florisson 2010)
- Industry end-users must be considered on a case-by-case basis
- As the blend level increases, from 1% to 12%, for example, additional precautions must be taken to minimize the impact on end-use systems
  - Haines et al. (2003) estimated the cost of upgrades or modifications for multiple blend levels for countries in Europe
  - Costs per country increased from millions to 100s of millions across a range of 3% to 12% blend levels
  - These costs include items such as sensors, engine controls, industry transmission line compressors, and household appliances

Blend level restrictions due to end-use appliances are considered the most stringent of the various types of limiting issues (Florisson 2009)

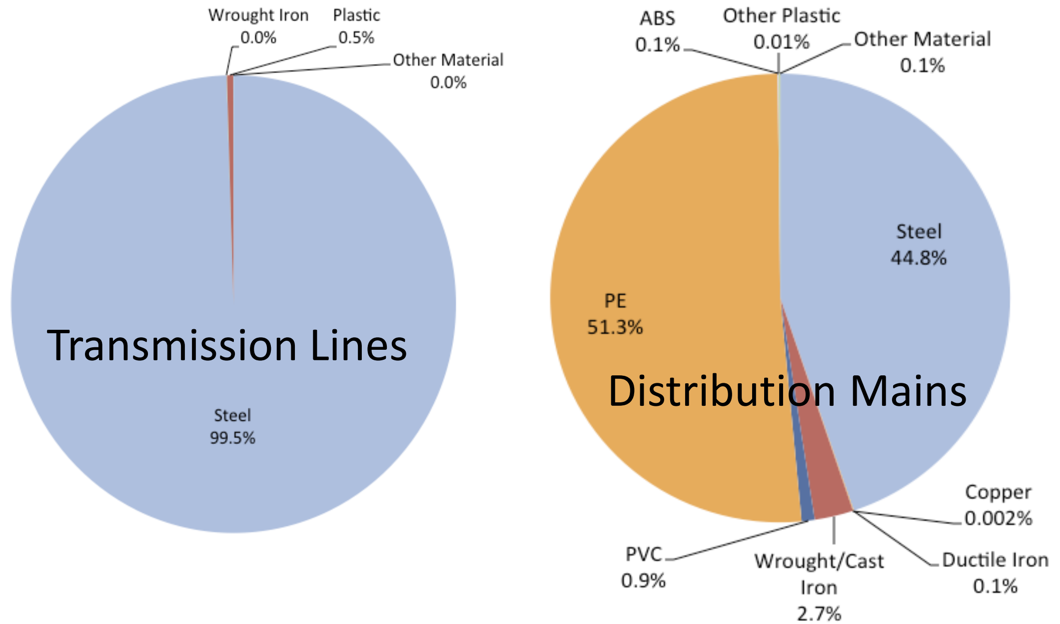
Safety

- It is difficult to make general claims about safety due to the large number of factors involved; detailed risk assessment results likely will vary from location to location.
- The ***probability*** of an incident and the ***consequence*** of the incident are combined into an overall risk factor. Risk ranking results from GTI are:
  - 10 is described as “minor,” 30 is “moderate,” and 50 is “severe”
- Blend levels at 20% by volume or less pose a minor risk of ignition, and in cases where ignition occurs, the severity is also minor.
- High blend levels can be safe in transmission lines, but additional risks are posed from the city gate through distribution lines.
  - **Distribution mains:** overall risk is minor for blends of 50% or less.
  - **Distribution service lines:** blends of 20% or less can be higher risk
- Risks for blends above 20% in distribution lines may be manageable, for example, by installing monitoring equipment. The precautions necessary to manage these risks would need to be assessed on a case-by-case basis.

Material Durability and Integrity Management

Material Durability

- Hydrogen embrittlement is mostly a concern at very high pressures and high concentrations (>50%)
- Most pipeline materials are not subject to hydrogen -induced failures



Integrity Management

- Hydrogen can be carried by existing natural gas transmission pipelines with only minor adaptations to the current Integrity Management Program
- Higher pressures (>2000 psi) and blends >50% pose greater challenges
- Transmission pipelines must be examined on a case-by-case basis
- Distribution lines in highly populated areas would require additional precautions
- Florisson et al (2010) suggest that hydrogen blends may result in a 10% increase in the cost of Integrity Management practices

Leakage

- Hydrogen is more mobile through plastic pipes and elastomeric seals than methane. Pipe walls have much more surface area than seals, so they are expected to be the source of the largest leaks.
- Leakage rates, based upon permeation coefficients, are 3-4 times faster through plastics compared to methane.
- Joints and seals are the major leakage points for steel and iron systems, and would be about 3 times faster than for methane.

Leakage Rate Estimate

- An estimate by GTI suggests that leakage rates would double with 20% hydrogen, but would still be economically insignificant at just 0.0002% of the total flow rate.

Might there be a GHG benefit from leakage?

- Given that hydrogen diffuses faster, and has a lower global warming potential if released, hydrogen blends may actually reduce GHG impacts compare to pure natural gas blends. This topic warrants additional study.

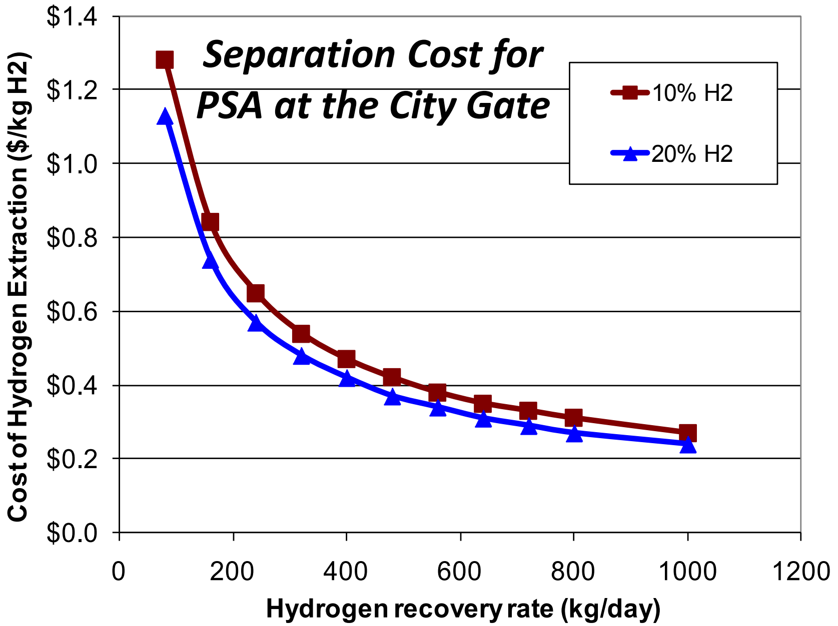
Downstream Extraction

Three gas separation technologies are reviewed as options for removing hydrogen downstream (e.g., at the city gate):

1. ***Pressure swing adsorption (PSA)***
2. ***Membrane separation***
3. ***Electrochemical hydrogen separation (EHS, or hydrogen pumping)***

PSA Separation Cost Estimate (NREL)

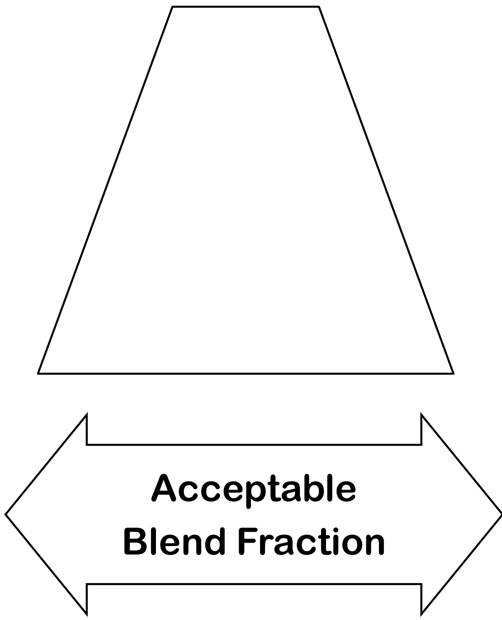
- Significant costs are incurred to re-pressurize the natural gas stream after hydrogen has been separated
- This costs can be avoided if separation occurs at the city gate
- Results suggest that, with some cost reductions, PSA separation at the city gate may be cost effective



Re-pressurization can incur an additional cost of $2.5-$4.50/kg

Which issues pose the greatest restrictions on the blend level?

The following order of restrictions has been proposed (Florisson 2012):



End-use Appliances

Safety

Pipeline materials

Proposed Future Work on Blending Renewable Hydrogen into the U.S. Natural Gas Pipeline System

1. Research and analysis of the costs associated with modifying U.S. pipeline integrity management systems to accommodate different levels of hydrogen blending.
2. Case studies assessing the pipeline system modifications required for specific U.S. regions at multiple hydrogen blend levels.
3. Detailed assessment of the impact of hydrogen blending on U.S. end-use systems, such as household appliances and power production technologies (i.e., engines and turbines).
4. Analysis of hydrogen blending in the near term (e.g., 5-10 years) as a means of economically increasing the output of renewable energy production facilities.
5. Dynamic analysis of the role of natural gas and hydrogen storage in future scenarios where hydrogen blending is prevalent in the U.S. natural gas systems.
6. Analysis of the role of hydrogen blending as a least-cost delivery option in the development of a hydrogen infrastructure for fuel cell electric vehicles.
7. Consideration of hydrogen blending as a strategic option to increase the public benefit derived from the existing U.S. natural gas infrastructure, with a focus on long-term implications for energy supply, energy security, integration of renewable natural gas, and greenhouse gas reductions.

Questions?

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Various sensitivities can be run to examine key input parameters

PRELIMINARY

Focus on price gasoline, FCEV efficiency, and rate of market adoption.

First two are compared across a range of values below to show change in required incentives (millions) during transition period.

36% Scenario

Price of gasoline offset from baseline ($/gal)	Fuel efficiency offset from baseline (miles/gge): -10	-7.5	-5	-2.5	0	2.5	5	7.5	10
-1.00	10,836	7,868	5,704	4,099	2,910	2,045	1,397	907	538
-0.75	6,176	4,243	2,871	1,894	1,192	706	352	131	60
-0.50	3,189	1,998	1,185	636	251	81	53	49	47
-0.25	1,402	709	254	69	50	47	46	44	42
0.00	384	77	50	46	44	43	42	40	39
0.25	52	47	44	43	41	40	39	38	37
0.50	45	43	41	39	38	38	37	36	36
0.75	42	40	38	37	37	36	35	35	34
1.00	39	38	37	36	35	35	34	34	33

66% Scenario

Price of gasoline offset from baseline ($/gal)	Fuel efficiency offset from baseline (miles/gge): -10	-7.5	-5	-2.5	0	2.5	5	7.5	10
-1.00	16,125	11,825	8,681	6,273	4,492	3,169	2,146	1,383	807
-0.75	9,340	6,491	4,429	2,936	1,848	1,080	501	152	57
-0.50	4,895	3,103	1,837	959	340	84	50	47	45
-0.25	2,159	1,071	345	70	48	45	44	42	41
0.00	541	78	48	46	43	41	40	39	38
0.25	50	46	43	42	40	39	38	37	37
0.50	45	42	41	40	38	37	36	36	35
0.75	41	40	39	38	36	35	35	34	34
1.00	39	38	37	36	35	34	33	33	33