BUILDING A WORLD OF DIFFERENCE

September 2013

NATURAL GAS INFRASTRUCTURE AND ELECTRIC GENERATION: PROPOSED SOLUTIONS FOR NEW ENGLAND

BASE CASE ANALYSIS

Prepared for NESCOE

BLACK & VEATCH
Building a world of difference.

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Presentation Outline

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Executive Summary - Base Case Natural Gas Demand in New England

- Black & Veatch anticipates moderate growth in New England natural gas demand throughout the analysis period, with growth of 360 million cubic feet per day (MMcf/d) expected from 2014 to 2029.
- Overall demand growth is expected to be driven by the residential, commercial, and industrial sectors as a result of economic recovery and market penetration in the residential and commercial sectors. Growth in residential and commercial demand is concentrated in Connecticut, as a result of the State's Comprehensive Energy Strategy.
- Electric sector demand for natural gas grows by 0.06% between 2014 and 2029. In contrast to the much more robust electric sector demand growth expected throughout the Lower 48 states, efficiency gains, demand response programs and renewable resources offset much of the customer load growth in New England.

Executive Summary - Base Case Natural Gas Supply Projections in New England

- Marcellus production continues to be one of the major supply sources serving New England. Marcellus production is expected to grow at 6% per year through the analysis period.
- Eastern Canadian production will also be an important supply source delivered to New England by the Maritimes and Northeast Pipeline ("MN&P").
    - Total Eastern Canadian production is expected to grow in the short term as Deep Panuke begins production in the summer of 2013
    - Regional production will then exceed 350 MMcf/d by 2014 but quickly decline from loss of SOEP production in 2018 and the steep decline curves faced by Deep Panuke producers
    - Production is expected to stabilize at 170-200 MMcf/d by 2021 as new supplies from New Brunswick Shale or offshore Newfoundland production come online.
- LNG imports are expected to serve approximately 350–400 MMcf/d of New England demand during peak winter months.
    - Supplies received at the Canaport LNG terminal (Saint John, New Brunswick) are expected to decline relative to historical norms when a firm supply agreement with Qatar expires in October 2013. Thereafter, imports at the terminal are expected to be driven by opportunistic deliveries based on spot prices.
    - Imports into the Everett terminal are expected to increase slightly by 50 MMcf/d towards the end of the analysis period due to growing New England demand.

Executive Summary - Base Case Natural Gas Infrastructure to Serve New England

- Existing capacity on Algonquin, Tennessee and Iroquois pipelines will be the major paths for Marcellus supplies entering New England.
- The Algonquin Incremental Market ("AIM") project is assumed to be put in service mid-2016.
- As the Constitution Pipeline becomes operational in 2015, moderate incremental capacity will be available to New England on Iroquois as it is able to deliver more volumes downstream to Connecticut and New York City via receipts from Wright.
- The availability of supply on Maritimes will be limited by eastern Canadian production and LNG imports from the Canaport terminal. Similarly, the availability of supply from the Everett terminal is limited by actual LNG import volumes.

Executive Summary - Base Case Natural Gas Market Trend in New England

- Black & Veatch forecasts an average monthly price and basis at Algonquin City-gates for the analysis period.
- Base Case natural gas price projections indicate that without the introduction of solutions to increase natural gas delivery capacity or moderate natural gas demand, New England will continue to experience significant price increases during winter months.
- Algonquin City-Gates basis is projected to moderate relative to the extremes experienced in the winter of 2012-2013, but continue to experience winter peaks averaging $3.00/MMBtu on a monthly basis.
  - The significant decline is attributable in part to the introduction of Deep Panuke supplies in 2013.
  - Projections also assume normal winter conditions that are more moderate than conditions experienced in the winter of 2012-2013.
- Significant basis increases and highly volatile daily pricing in winter months are projected to return in the winter of 2022-2023 as demand grows to outpace natural gas delivery capacity serving the region, and higher-cost supply sources from Eastern Canada are introduced.
- New England electricity prices will remain high in winter months in response to high gas prices.

Executive Summary – Long-term Solutions Tested

- Consistent with Phase II recommendations, Black & Veatch examined three potential long-term solutions to New England's natural gas infrastructure constraints under the Base Case Scenario:
  - Cross-Regional Natural Gas Pipeline - A 1.2 Bcf/d natural gas pipeline to provide New England with additional natural gas supplies and reinforce existing natural gas infrastructure.
  - Economic Based Energy Imports - An electric transmission line capable of importing 1,200 megawatts (MW) of energy from Canada. The amount of energy imported by New England will be based upon the simulated hourly energy needs and price differentials between New England and alternative markets.
  - Firm-Based Energy Imports - An electric transmission line, similar to the economic based energy imports, that delivers *firm* energy supplies, a constant amount of energy equal to the maximum capacity of the transmission line enabled through the construction of additional generation infrastructure.

Executive Summary – Short-term Solutions Tested

- Consistent with recommendations from Phase II, Black & Veatch examined two potential short-term solutions to New England's natural gas infrastructure constraints under the Base Case scenario:
  - LNG Imports - An additional 300 MMcf/d of LNG imports to the Canaport and Everett LNG terminals during the peak winter months of January and February.
  - Dual-Fuel and Demand Response - An additional 2.3 Terawatt hours ("TWh") of dual-fuel, fuel-oil-fired generation coupled with demand response across New England.

Executive Summary – Calculate Economic Benefits to Natural Gas End Users

- Benefits to natural gas end-users, including residential, commercial, and industrial customers, are calculated by multiplying anticipated reductions in wholesale natural gas prices by consumption volumes affected by this price reduction.
- In general, most residential, commercial and industrial customers receive gas from LDCs. LDCs are required to support their ultimate deliverability by contracting firm transportation capacity on natural gas pipelines and long-term supply purchases, so only limited amounts of “swing” supplies are purchased by New England LDCs at the region’s prevailing wholesale market price as measured by Black & Veatch in this analysis using Algonquin City-Gates price point.
- For the analysis, Black & Veatch estimated that total volume linked to regional market price to include:
    - 10% of industrial demand
    - 3% of residential and commercial winter demand
    - Total volume ranges from 19 – 25 Bcf per year

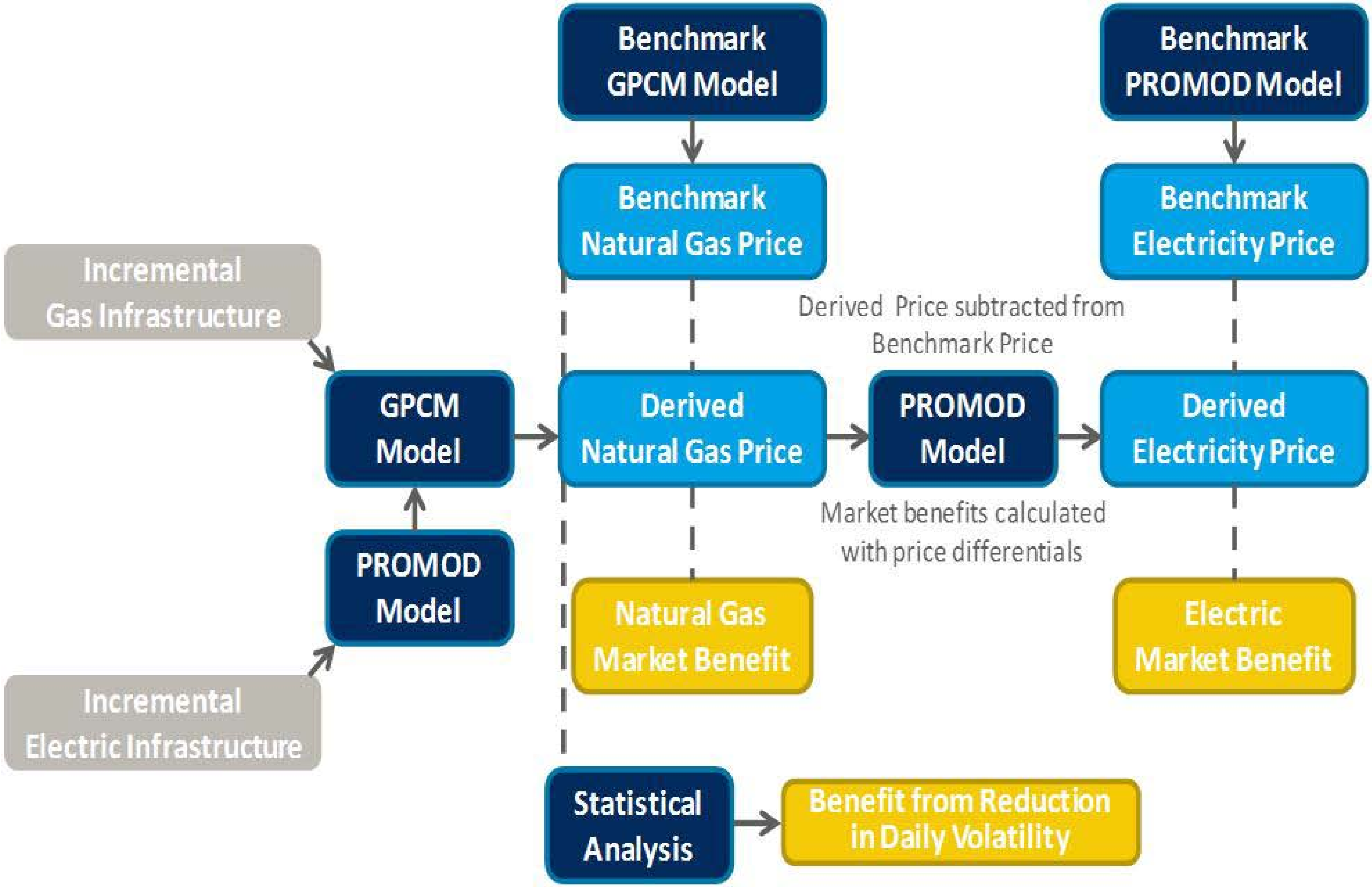
Executive Summary – Calculate Economic Benefits to Electric Customers

- Given that a majority of New England power generators purchase natural gas supplies at wholesale spot prices, Black & Veatch assumed for this study that reductions in electricity prices provided by infrastructure solutions benefit all New England electric customers.
- New England's electricity prices across all ISO-NE zones are highly correlated with regional wholesale natural gas prices.
- Benefits to electric customers are calculated as the reduction in market energy prices in each ISO-NE zone multiplied by total energy consumption in that zone.
- The benefits are calculated using monthly average electricity price reductions resulted from reduction in monthly natural gas prices.

Executive Summary – Calculate Economic Benefits from Volatility Reduction

- In addition to the overall price decreases modeled above, natural gas end-users and electric customers also benefit from reductions in daily natural gas price volatility.
- Incremental gas infrastructure additions, increased gas supply, or reduced power-sector demand all provide relief from supply constraints and will also reduce daily price volatility. For example, New England winter basis could increase to more than $20/MMBtu in a single day, while increase in summer daily basis never exceeds $1/MMBtu, given the absence of capacity constraints.
- Because power generators make dispatch decisions based on daily gas prices, daily price volatility for gas has a very significant impact on electric customers.
- The economic benefits of volatility reduction were estimated as reduction of extremely high daily prices through a statistical modeling approach.

EXECUTIVE SUMMARY - ESTIMATION OF BENEFITS



Executive Summary – Costs of Tested Solutions

- The costs of solutions should reflect the costs that New England customers pay in order to receive the benefits described previously.
- For long-term solutions that require incremental infrastructure construction, the costs are best approximated with a Cost-of-Service (COS) concept. This concept is based on the understanding that capital costs incurred in the construction of infrastructure are amortized over the useful life of the project and should provide a fair return to project investors. In addition, for each year the facilities are in operation, certain costs attributable to the operation of the facilities are incurred and these costs need to be recovered as well.
- Black & Veatch estimates this cost on a levelized basis over a 20-year period, offsetting the natural decline of annual COS over time when the asset is depreciated.
- The true costs of short-term solutions are approximated by the premium for holding the alternative supply option.
    - Costs of LNG imports are estimated as total prices paid for peaking LNG spot cargos less costs of same amount of gas valued at Henry Hub.
    - Costs of dual fuel and demand response solutions are estimated as generators' production costs less revenue received from selling the power, similar to uplift costs.

Executive Summary – Costs of Tested Solutions

	Cross-Regional Pipeline	LNG Imports	Dual Fuel and DR	Economic Energy	Firm Energy
Assumed Cost Components	Annual carrying cost of incremental pipeline	Annual cost of ensuring incremental LNG supply	Out-of-market costs ("uplift") to ensure generator cost recovery	Annual carrying cost of incremental transmission line in the US	Annual carrying costs of: 1. Incremental transmission line in the US 2. Building a new dam
Solution Description	1.2 Bcf/d pipeline into Eastern Massachusetts	4-5 additional cargo ships (18 Bcf)	2.3 Twh of energy in Jan & Feb, M-F on peak	1200 MW HVDC from HQ to ENE	1200 MW HVDC from HQ to ENE + new dam = 24/7/365

Executive Summary – Economic Benefits and Costs for Long-term Solutions

Total Benefits for Long-Term Infrastructure Solutions (in Million Dollars)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Regional Pipeline	$ 97	$ 114	$ 107	$ 121	$ 165	$ 177	$ 335	$ 392	$ 381	$ 418	$ 478	$ 525	$ 519	$ 3,827	$ 294
Economic Based Canadian Electric Imports	$ -	$ 109	$ 131	$ 153	$ 182	$ 206	$ 343	$ 334	$ 298	$ 322	$ 311	$ 382	$ 304	$ 3,075	$ 256
Firm Canadian Electric Imports	$ -	$ 255	$ 269	$ 362	$ 388	$ 395	$ 568	$ 530	$ 529	$ 537	$ 501	$ 572	$ 499	$ 5,405	$ 450

Total Costs for Long-Term Infrastructure Solutions (in Million Dollars)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Regional Pipeline	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 2,288	$ 176
Economic Based Canadian Energy Imports	$ -	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 219	$ 2,628	$ 219
Firm Contract Based Canadian Energy Imports	$ -	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 4,668	$ 389

Net Benefits for Long-Term Infrastructure Solutions (in Million Dollars)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Regional Pipeline	$ (79)	$ (62)	$ (69)	$ (55)	$ (11)	$ 1	$ 159	$ 216	$ 205	$ 242	$ 302	$ 349	$ 343	$ 1,539	$ 118
Economic Based Canadian Energy Imports	$ -	$ (110)	$ (88)	$ (66)	$ (37)	$ (13)	$ 124	$ 115	$ 79	$ 103	$ 92	$ 163	$ 85	$ 447	$ 37
Firm Contract Based Canadian Energy Imports	$ -	$ (134)	$ (120)	$ (27)	$ (1)	$ 6	$ 179	$ 141	$ 140	$ 148	$ 112	$ 183	$ 110	$ 737	$ 61

Executive Summary – Economic Benefits and Costs for Short-term Solutions

Total Benefits for Short-Term Solutions (in Million Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Short-term LNG Imports	$ 289	$ 297	$ 227	$ 74	$ 69	$ 67	$ 68	$ 119	$ 106	$ 278	$ 342	$ 307	$ 331	$ 385	$ 441	$425	$ 3,824	$ 232
Dual Fuel and Demand Response	$ 425	$ 349	$ 274	$ 97	$ 104	$ 104	$ 105	$ 158	$ 141	$ 337	$ 385	$ 325	$ 346	$ 385	$ 440	$365	$ 4,342	$ 266

Total Costs for Short-Term Solutions (in Million Dollars)

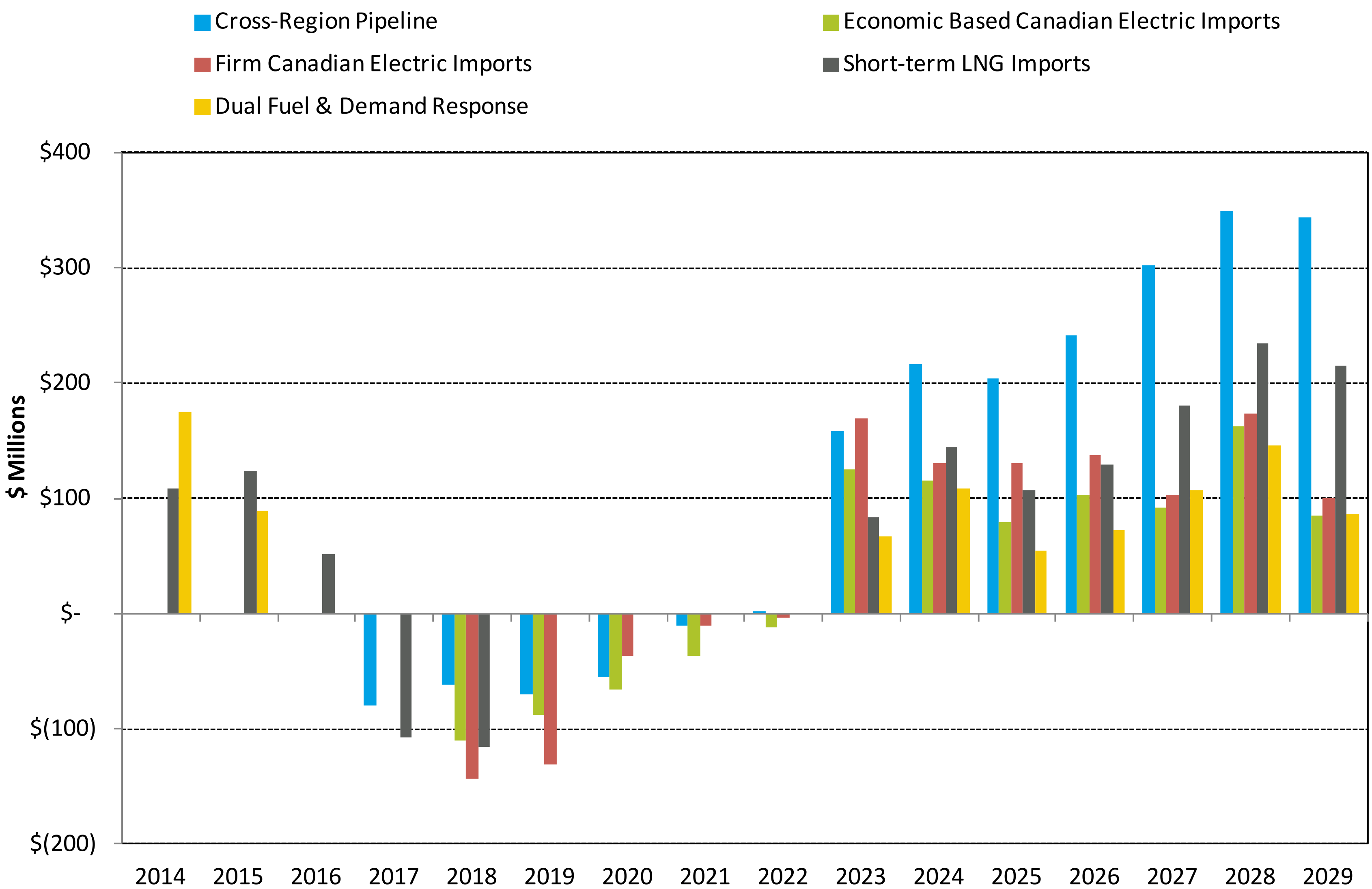
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Short-term LNG Imports	$ 180	$ 174	$ 175	$ 182	$ 184	$ 186	$ 189	$ 191	$ 193	$ 195	$ 197	$ 199	$ 202	$ 204	$ 206	$209	$ 3,066	$ 195
Dual Fuel and Demand Response	$ 250	$ 260	$ 275	$ 265	$ 267	$ 266	$ 275	$ 265	$ 268	$ 269	$ 277	$ 270	$ 275	$ 277	$ 294	$279	$ 4,333	$ 273

Net Benefits for Short-Term Infrastructure Solutions (in Million Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Short-term LNG Imports	$ 109	$ 123	$ 52	$ (107)	$ (115)					$ 83	$ 145	$ 108	$ 129	$ 181	$ 234	$216	$ 1,157	$ 96
Dual Fuel and Demand Response	$ 175	$ 89								$ 68	$ 108	$ 55	$ 72	$ 107	$ 146	$ 86	$ 906	$ 101

Note - For years in which dual-fuel and demand response are expected to result in negative net benefits, the option not to pursue the solution is reflected. For LNG, an initial five-year supply contract was assumed, which results in two years of negative net benefits after the AIM in-service date of 2016. Excluding the two years of negative benefits would have increased the average annual net benefits to $138 million for the LNG imports solution.

Net Benefits Comparisons Across Solutions



Executive Summary – Recommendations

- Short-term and long-term solutions are needed to relieve the natural gas market constraints in New England under the Base Case.
- Construction of a Cross-Regional Natural Gas Pipeline provides the greatest net benefits of the large-scale infrastructure improvements considered in this study. Based on the findings under the Base Case Scenario, and assuming the underlying assumptions reflect future market conditions, Black & Veatch recommends the construction of a Cross-Regional Natural Gas Pipeline as a long-term solution.
- Strategies that can be quickly deployed will play a vital role in alleviating infrastructure constraints. Black & Veatch recommends that dual-fuel generation, demand response measures, and the seasonal purchase of LNG cargoes be deployed immediately.

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  - Base Case – With Dual Fuel Generation

Base Case Scenario Assumptions

Power

1. Gross New England electric load grows approximately 1.1% per year as projected in the 2012 Capacity, Energy, Load and Transmission ("CELT") report. Net electric energy load, which incorporates the effect of energy efficiency programs, grows approximately 0.3% per year over the same period.
2. Environmental policies and competitive economic pressure trigger significant retirements of coal and oil-fired electric generation Each New England state to meet its RPS standards;
3. A federal cap-and-trade program on carbon emissions is in effect by 2020, which results in later-period capacity additions that are, separate from renewable resources discussed below, assumed to be exclusively gas-fired.
4. Growth in renewable generation capacity dominates capacity additions in the early years to allow each New England state to meet its Renewable Portfolio Standards ("RPS") goals.

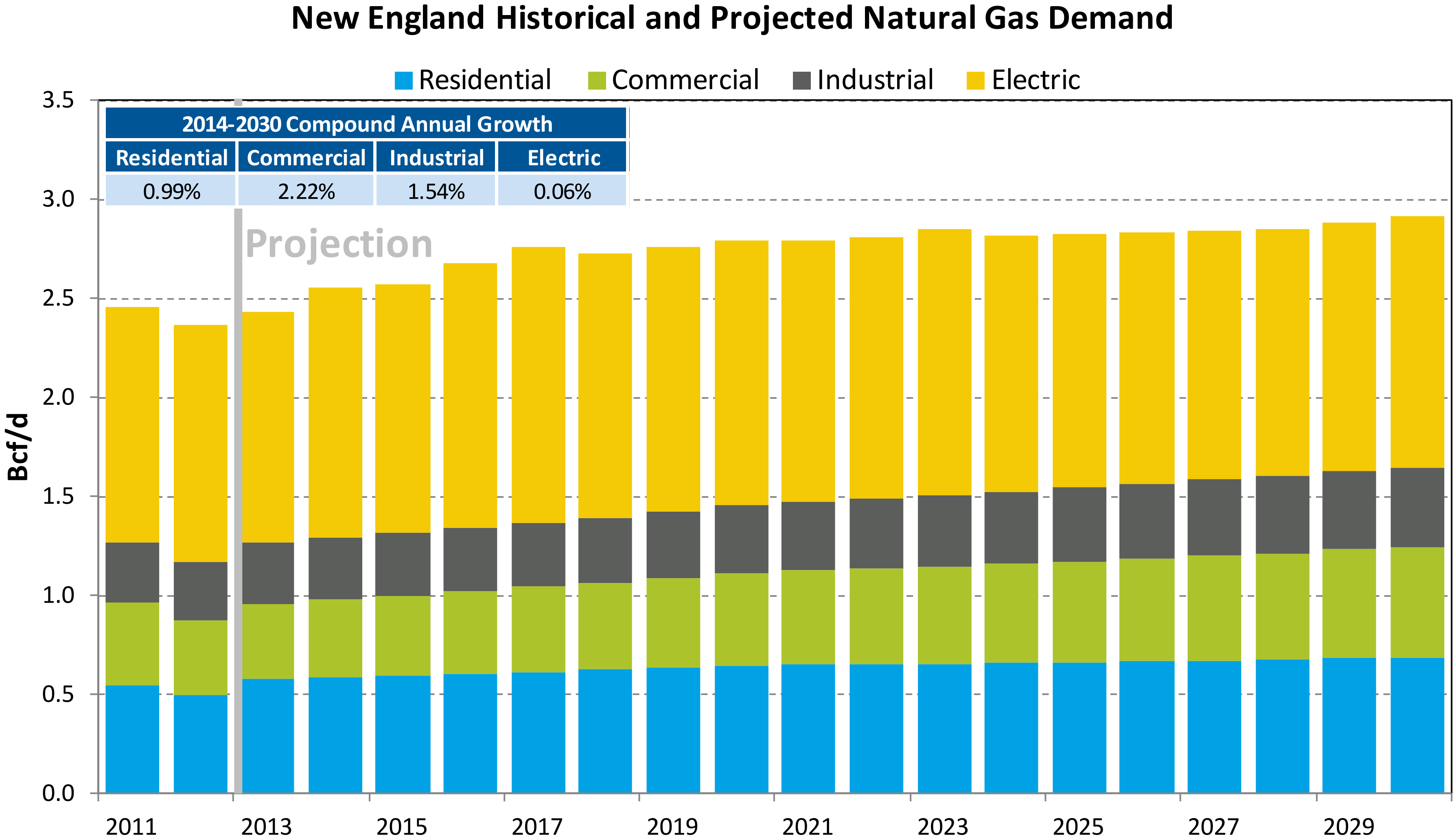
Natural Gas

1. Demand from residential, commercial and industrial sectors in New England states (except for Connecticut) grows at the average pace of 1.6% per annum.
2. For the state of Connecticut, the goal laid out in the state's Comprehensive Energy Strategy is met, increasing Connecticut's residential and commercial natural gas penetration rate to 50% by 2020.
3. LNG Exports from Gulf Coast and West Coast.
4. Marcellus grows at 6% per year; Eastern Canadian production increases sharply in 2014 to >350 MMcf/d and then gradually declines through 2020.
5. Algonquin Incremental Market (AIM) expansion in-service by 2016.
6. Everett MA (Distrigas) supplies will sharply decline relative to 2011 but gradually increase starting in 2019.
7. Saint John NB Canada (Canaport) supplies will decline after firm supply contract expires in Oct 2013.

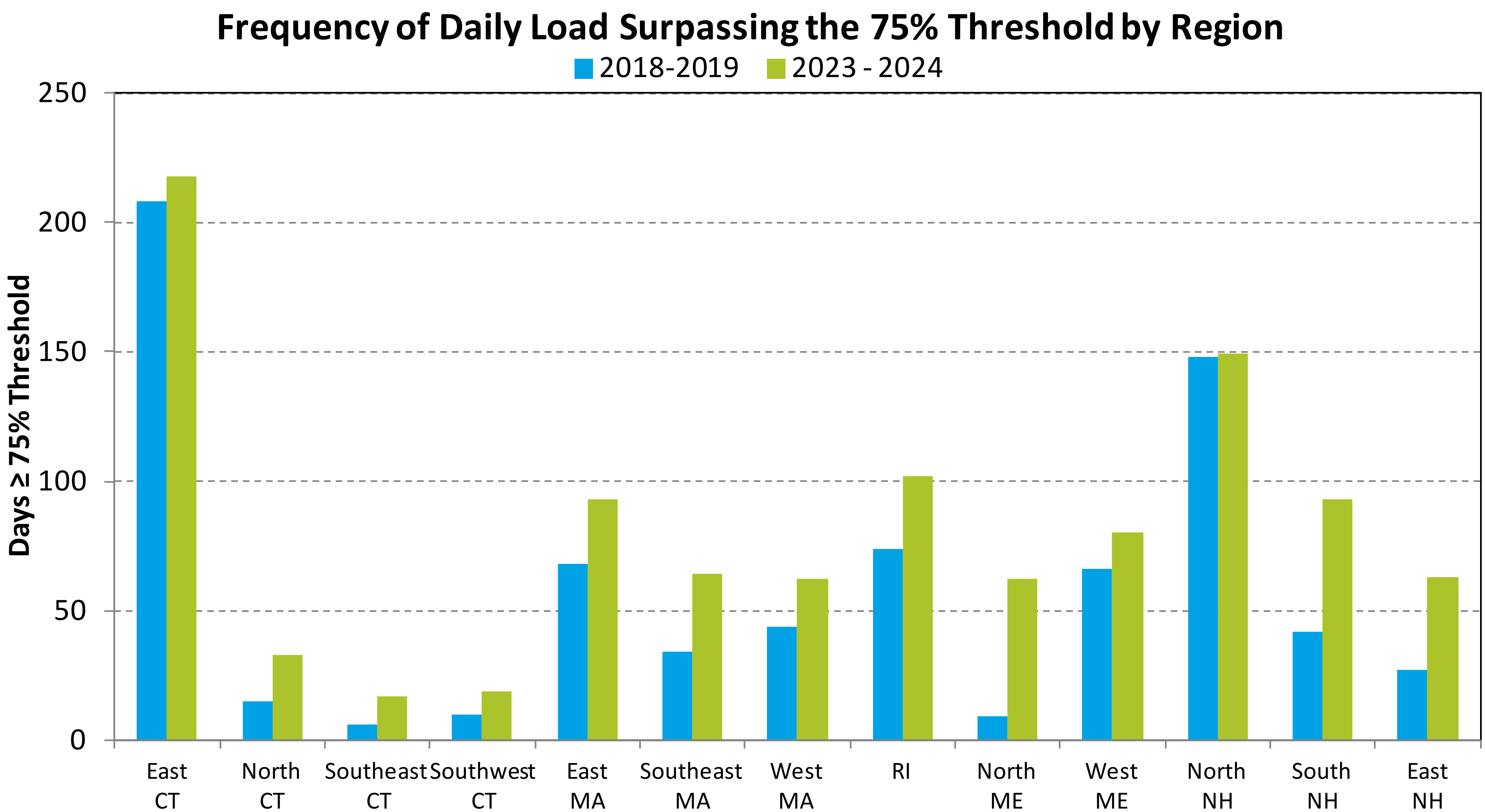
Sensitivity Model Runs for the Base Case

	BASE CASE
Long-Term Solutions	Cross-Regional Natural Gas Pipeline
	Firm-Based Energy Imports (firm-contracted electricity from eastern Canada)
	Economic-Based Energy Imports (market-driven electricity from eastern Canada)
Short-Term Solutions	LNG Imports
	Dual-Fuel Generation and Demand Response

New England Demand Growth Projections – Base Case

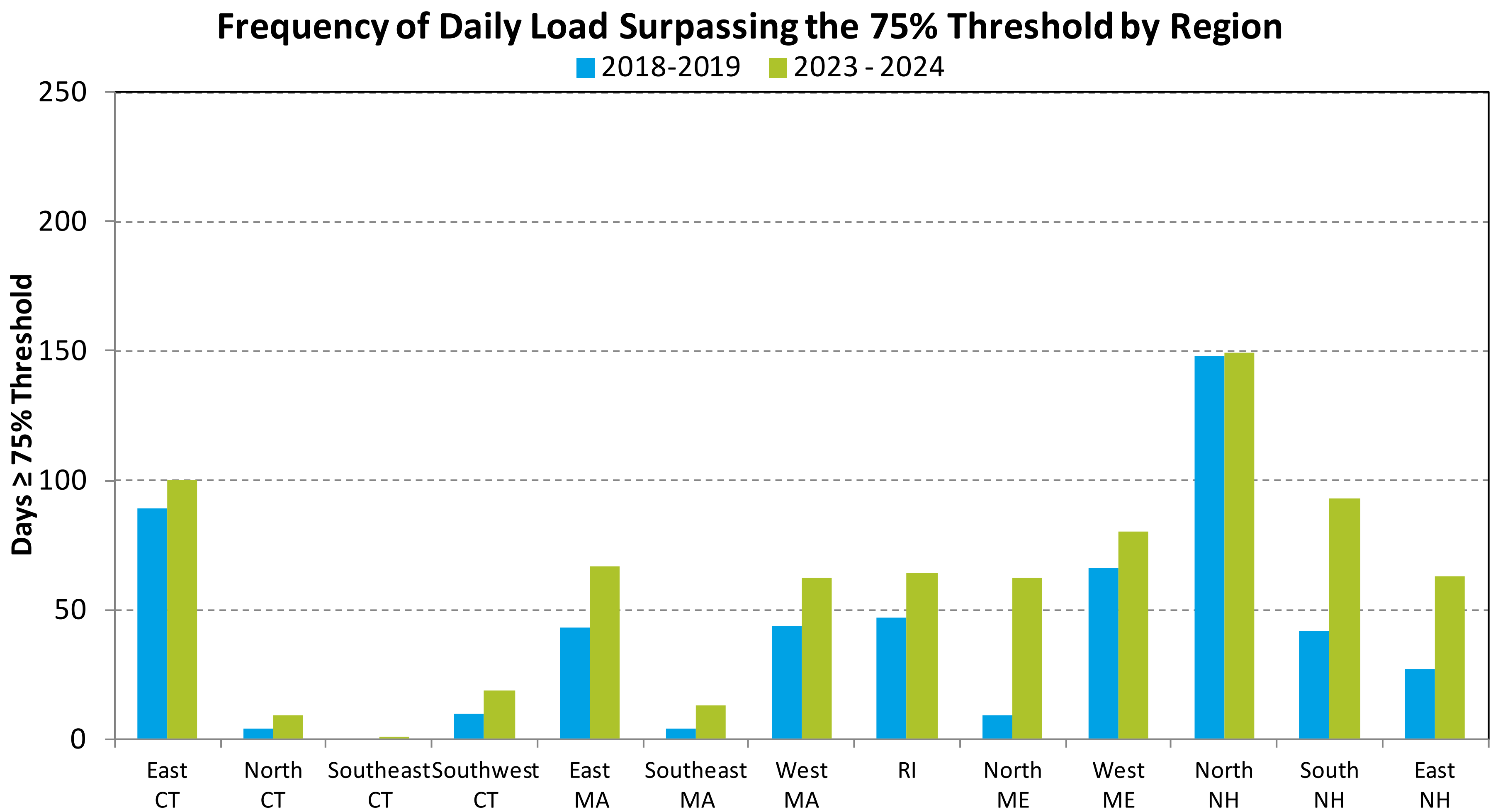


Without Spectra's AIM Project, pipeline constraints could occur for more than 100 days in some sub-regions



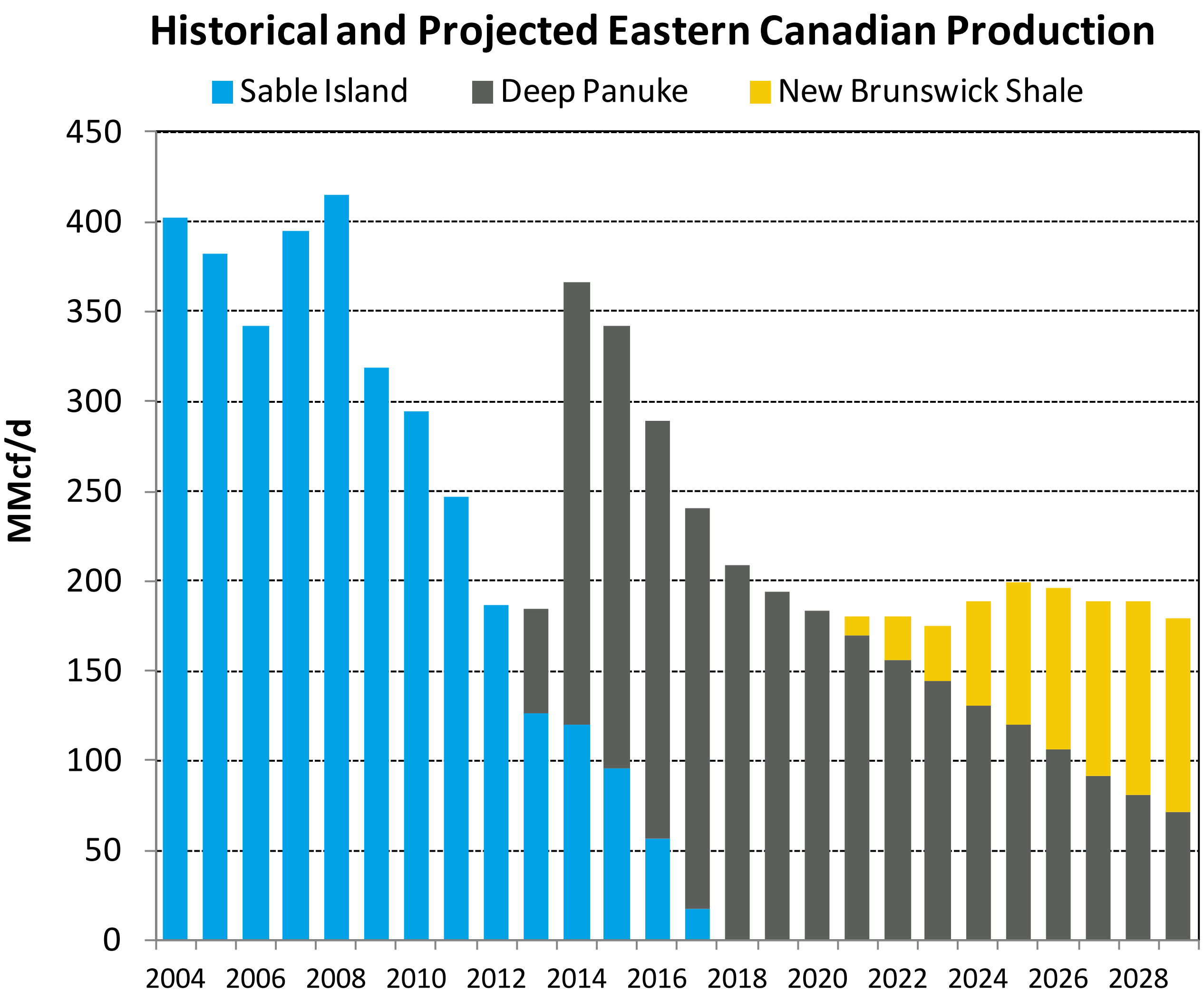
Source: Black & Veatch Analysis

Spectra's AIM Project significantly reduces constraint days for Connecticut, Massachusetts and Rhode Island



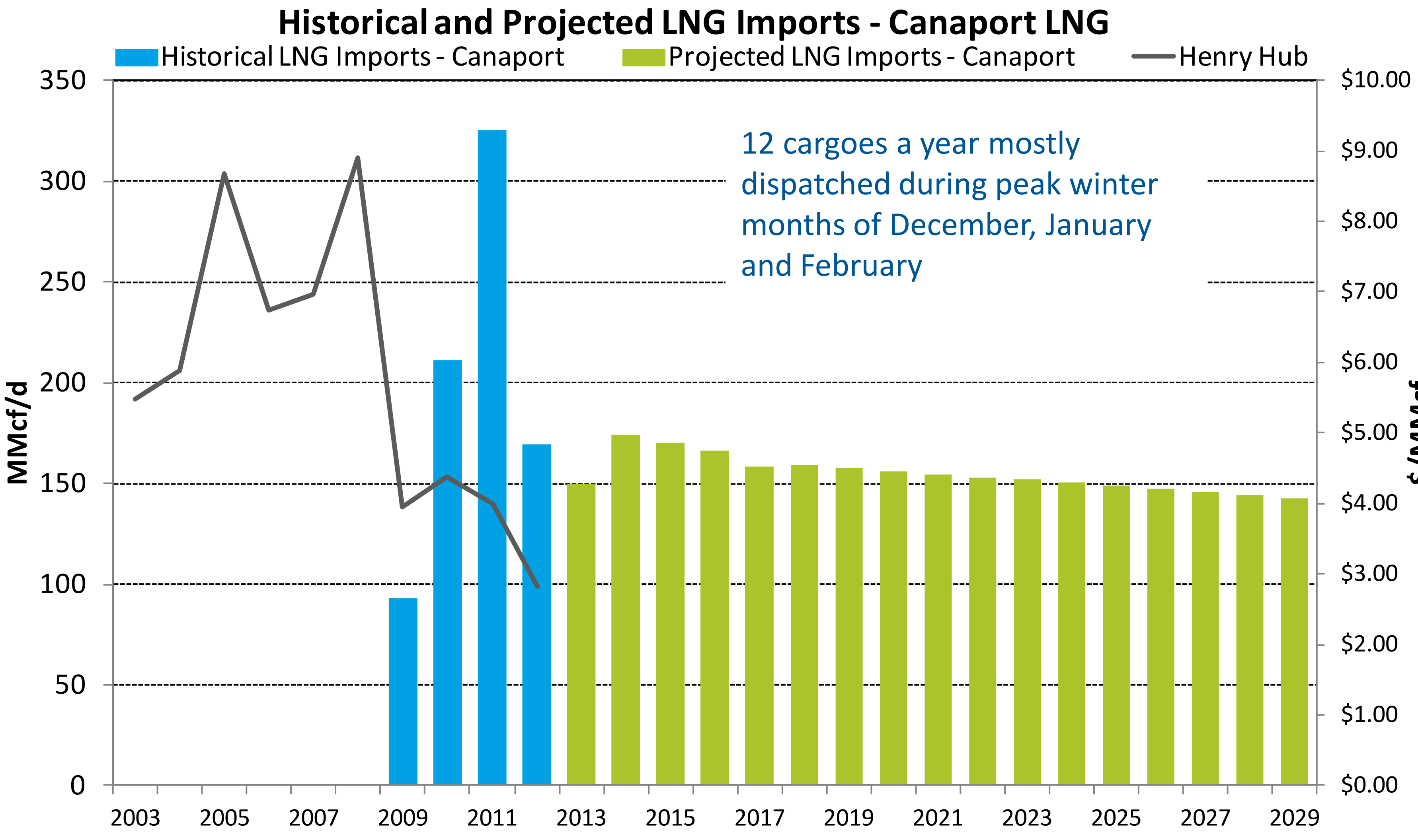
Source: Black & Veatch Analysis

Eastern Canadian Production Projection – Base Case

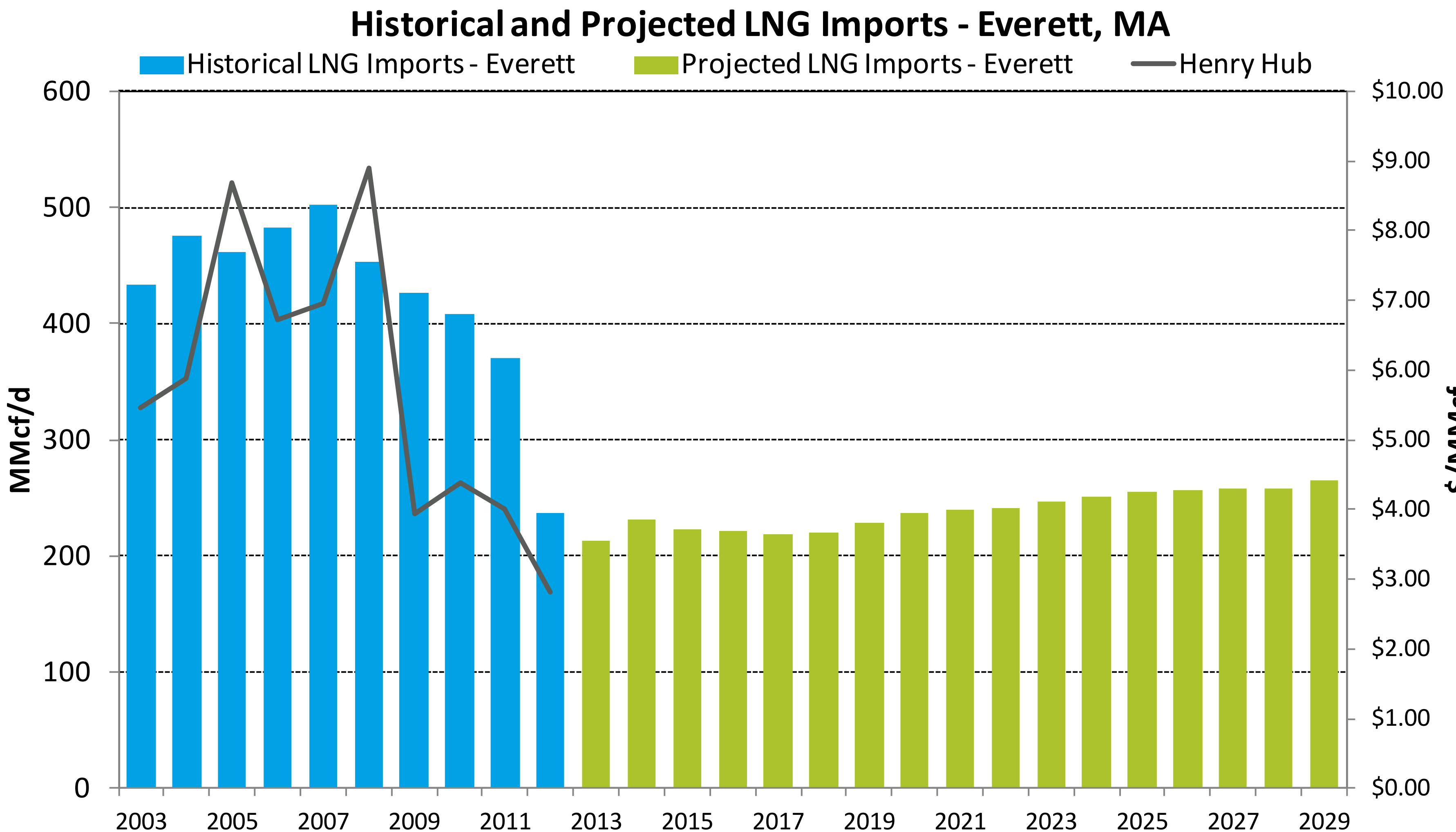


- Sable Island Offshore Project production has been in sharp decline. NEB expects it to cease production by 2018
- Encana's Deep Panuke project has been delayed multiple times, latest expected in-service date is August 2013
- New production sources are assumed to come on-line according to NEB:
  - Newfoundland Offshore
  - New Brunswick Shales

LNG Import at Canaport – Historical and Projected Flows



LNG Import at Everett – Historical and Projected Flows



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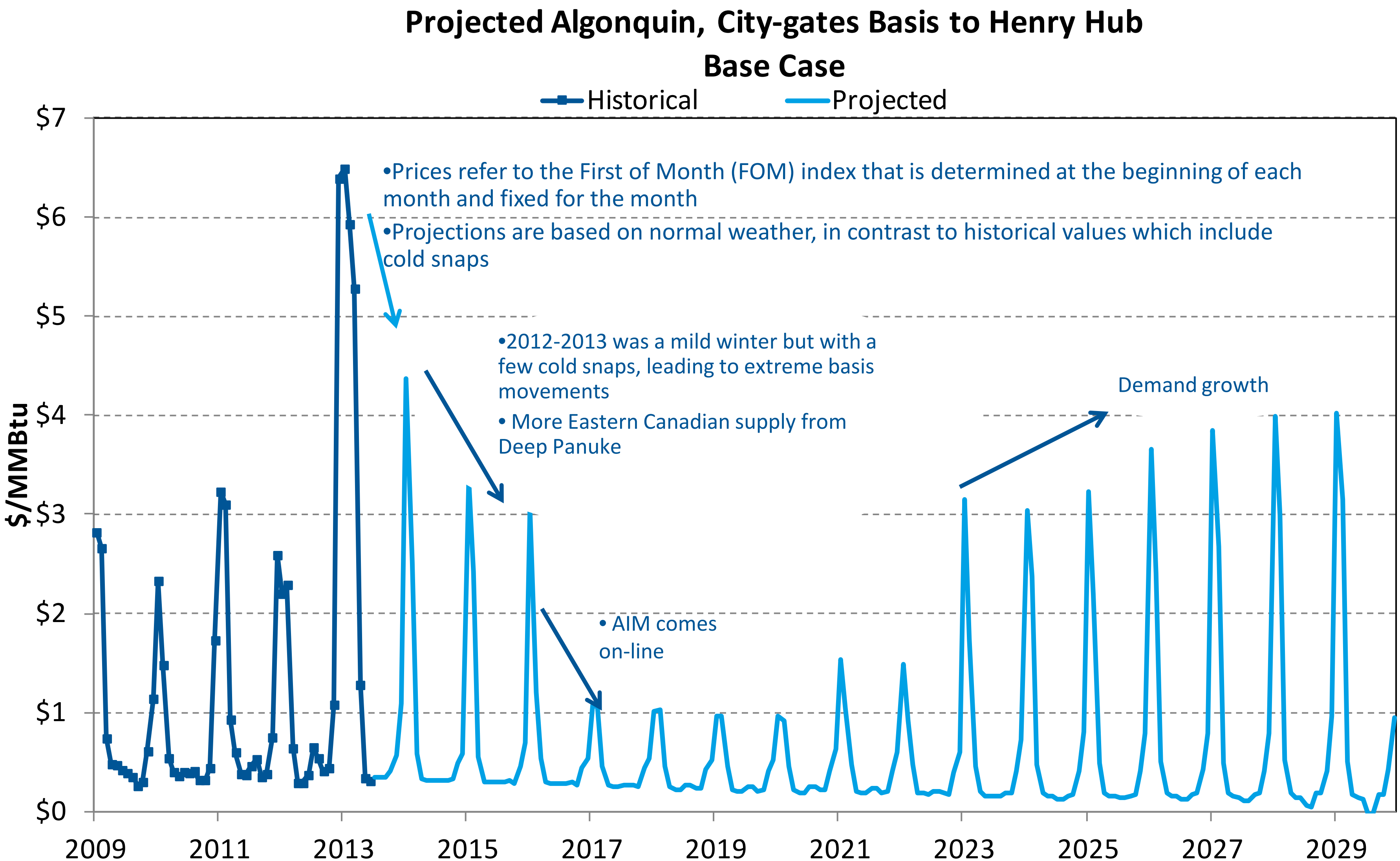
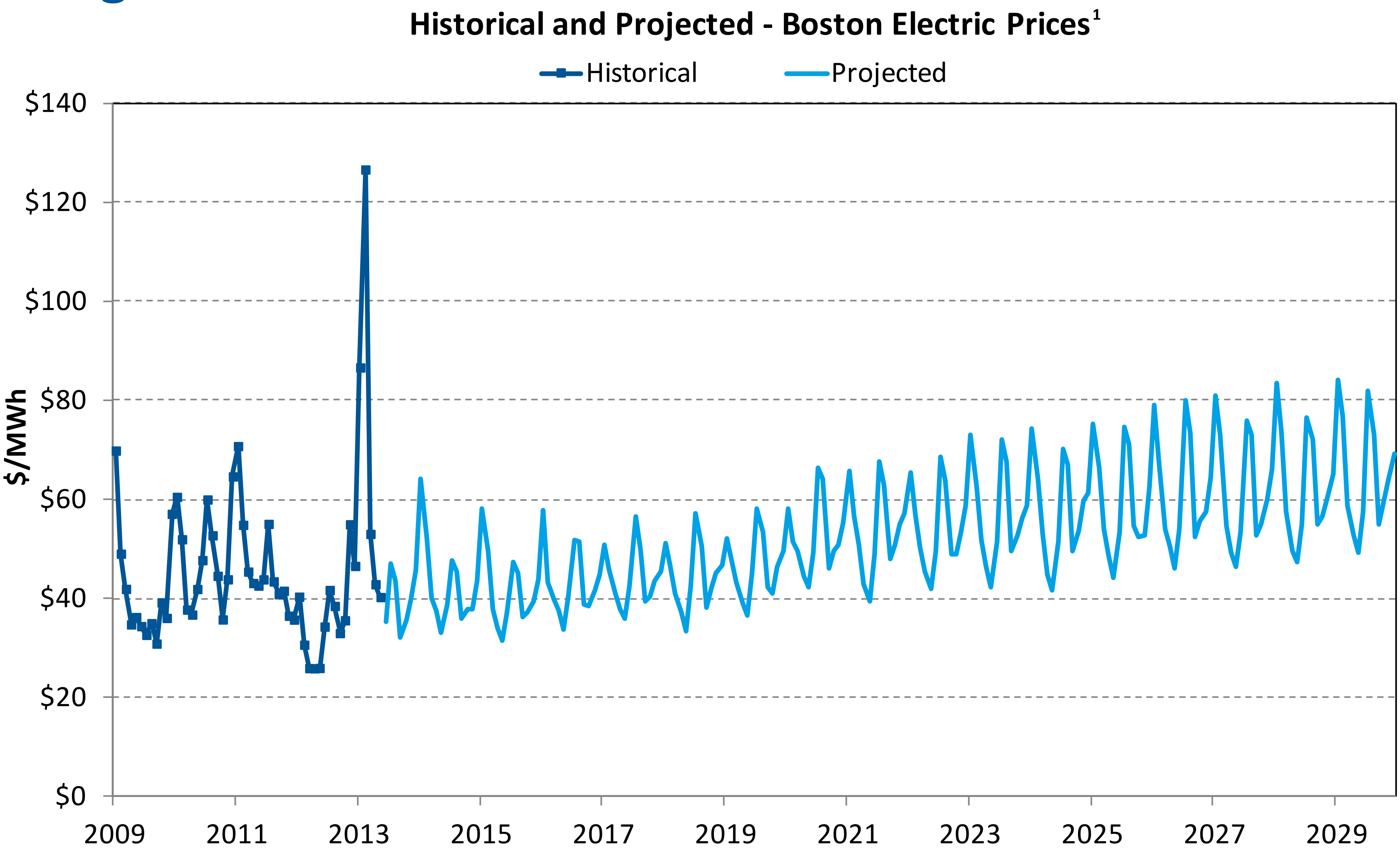
Historical and Projected Natural Gas Basis in New England – Base Case No Incremental Infrastructure

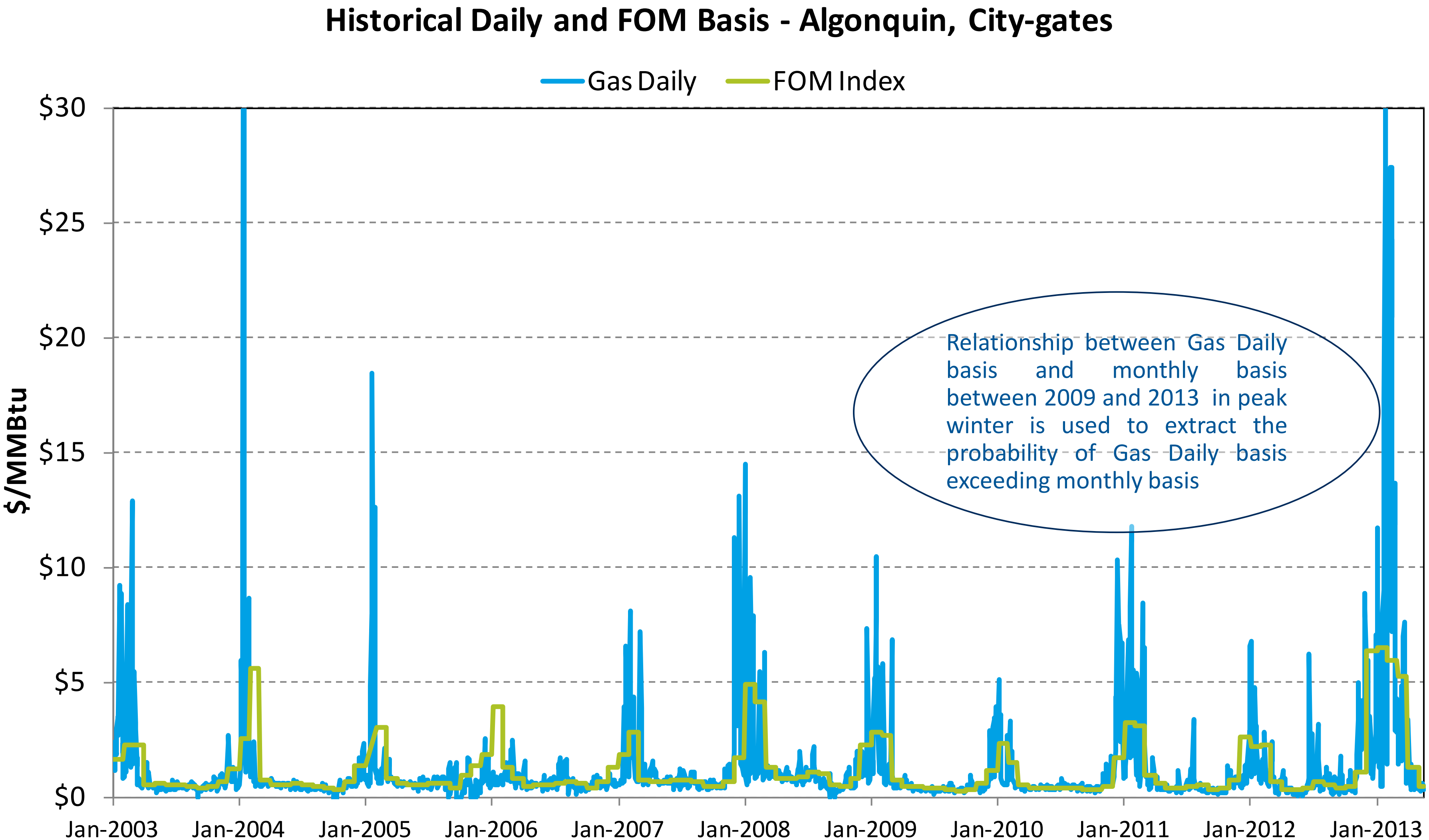


Historical and Projected Electricity Price in New England – Base Case No Incremental Infrastructure

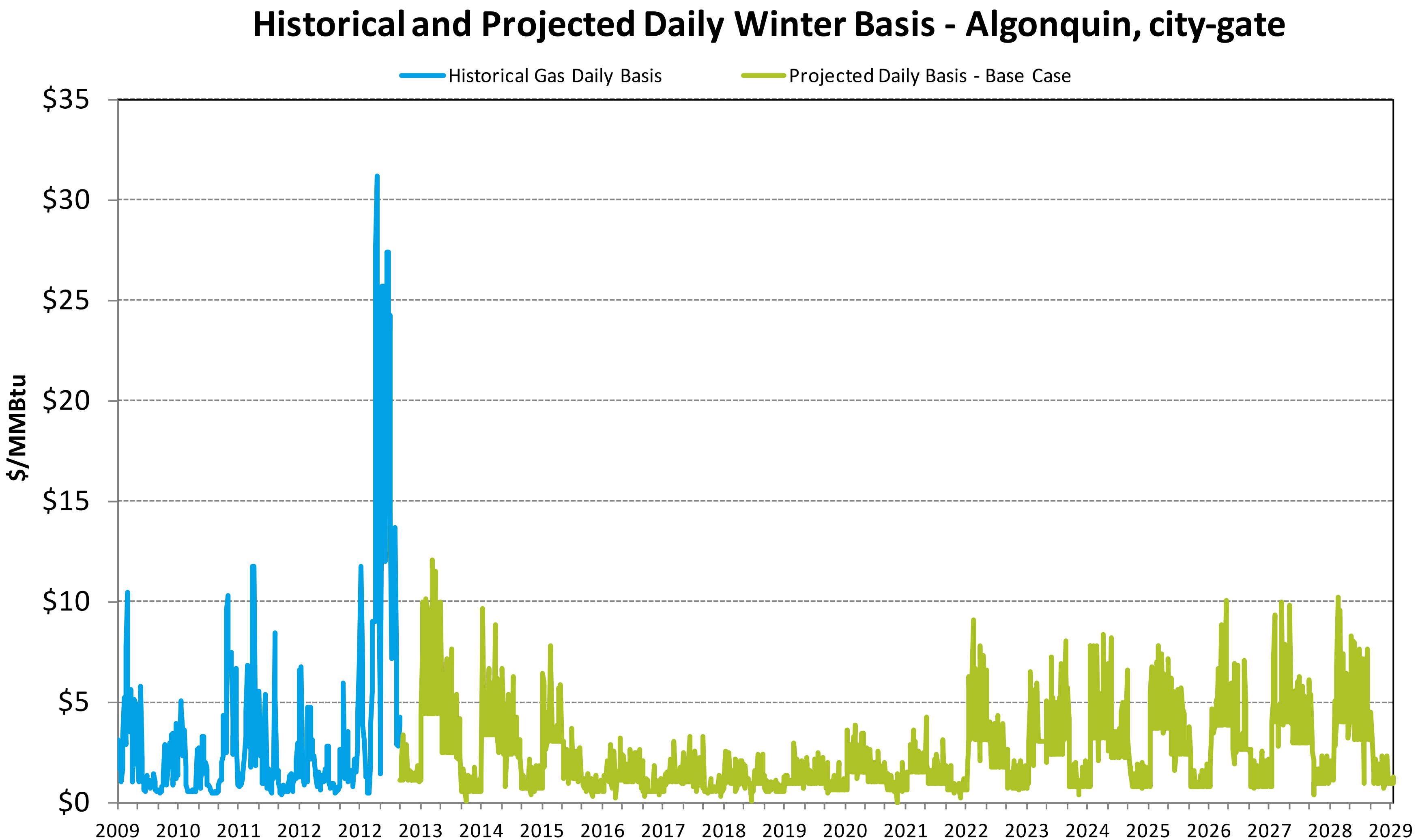


[1] For the graphic presentation of the electricity price impacts of different solutions in this report, Black & Veatch chose Boston as a corresponding electricity price location to Algonquin City-Gates. Black & Veatch selectively graphed the price impacts at other New England electricity zones to confirm that they are similar to Boston's.

Natural Price Comparison: Gas Daily vs. First-of-Month Basis



Historical and Projected Winter Daily Basis – Base Case



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Base Case Sensitivity – Cross-Regional Natural Gas Pipeline

- A natural gas pipeline with a design capacity of 1.2 Bcf/d originating in Upstate New York and terminating in Eastern Massachusetts could potentially relieve constraints during peak winter months and provide the baseload and peak hour flexibility necessary to meet future demand growth.

- The Cross-Regional Natural Gas Pipeline would originate at Wright, the existing Tennessee Gas Pipeline ("Tennessee") and Iroquois interconnect in Schoharie County, New York, and terminate at Dracut, Tennessee Gas Pipeline's interconnect with M&NP in Middlesex County, Massachusetts.

- This pipeline is assumed to commence service in the spring of 2017 and access gas supplies from existing capacity on Tennessee and Iroquois. It is also anticipated to access supplies from the proposed Constitution pipeline which is expected to commence service in early 2015.

Cost of the Cross-Regional Natural Gas Pipeline

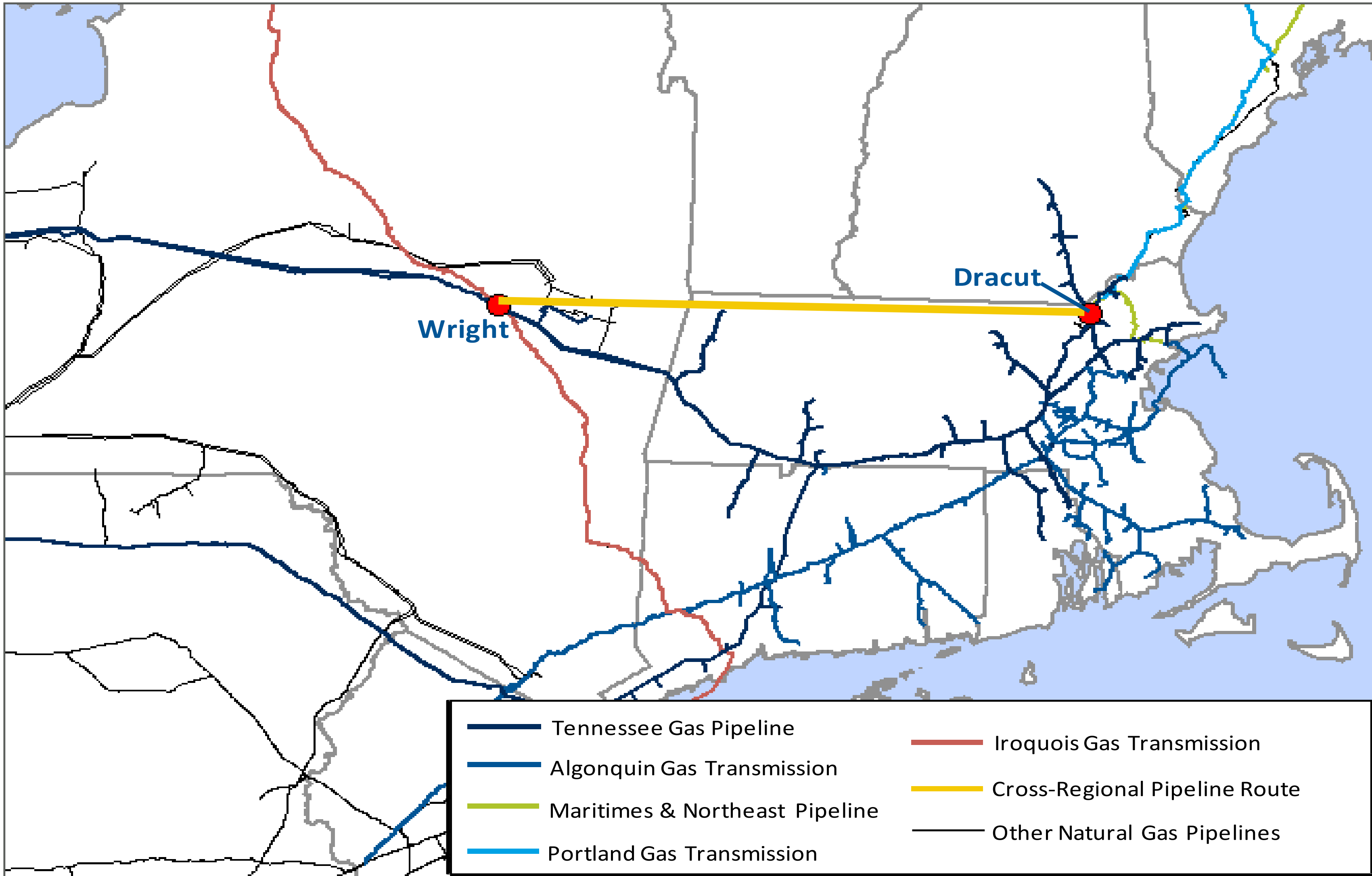
- Black & Veatch estimates that the Cross-Regional Natural Gas Pipeline could be constructed for approximately $1.2 billion.

- Representative capital costs for greenfield projects, like the Cross-Regional pipeline, in the Northeast U.S. were estimated using Constitution Pipeline's proposed transportation rate of $0.76/dth/day.
  - The projected costs could change based on future steel costs, the diameter of the pipeline, the routing and construction delays related to local opposition.

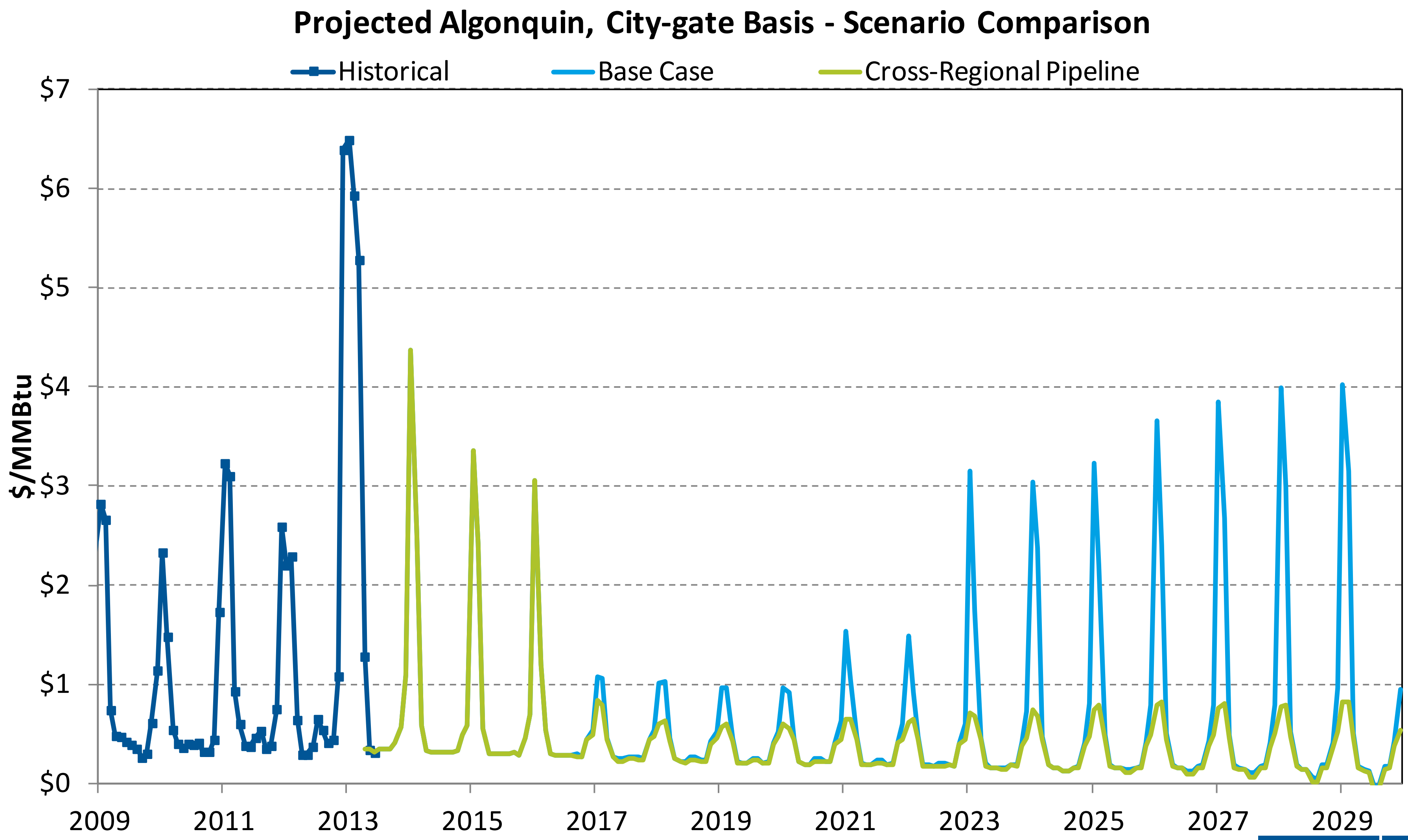
- Assuming that 100% of its capacity is contracted, the pipeline could potentially offer a 100% load factor transportation rate of $0.45/Dth/day.
  - However, lower-than-anticipated capacity subscription could lead to significant increases in the per-unit rate. For example, the per-unit rate would double if the pipeline capacity is only 50% subscribed.

- Rates were estimated using a capital structure considered to be representative of major interstate pipelines serving New England and levelized over a 20-year period.

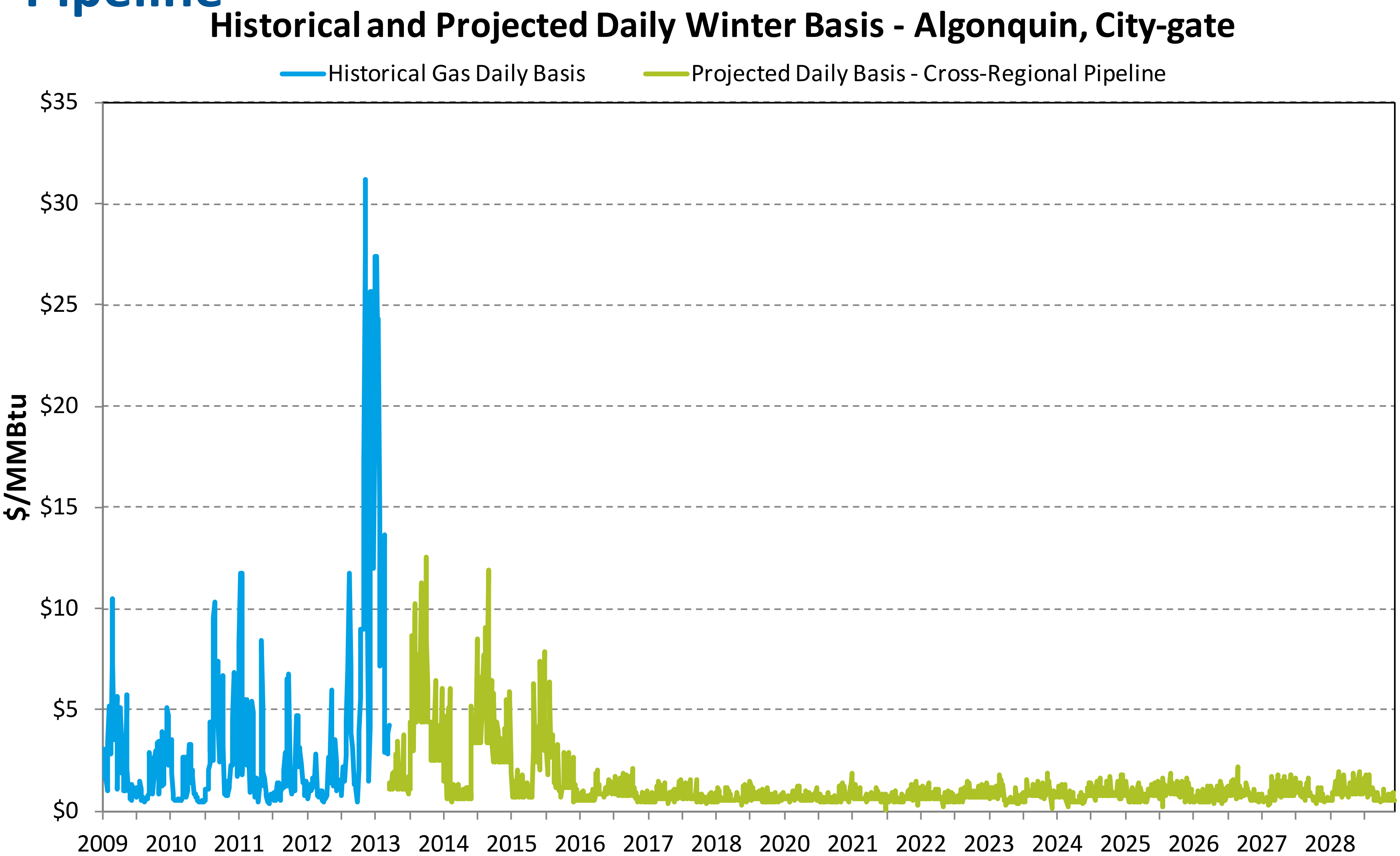
Illustrative Cross-Regional Natural Gas Pipeline Routing



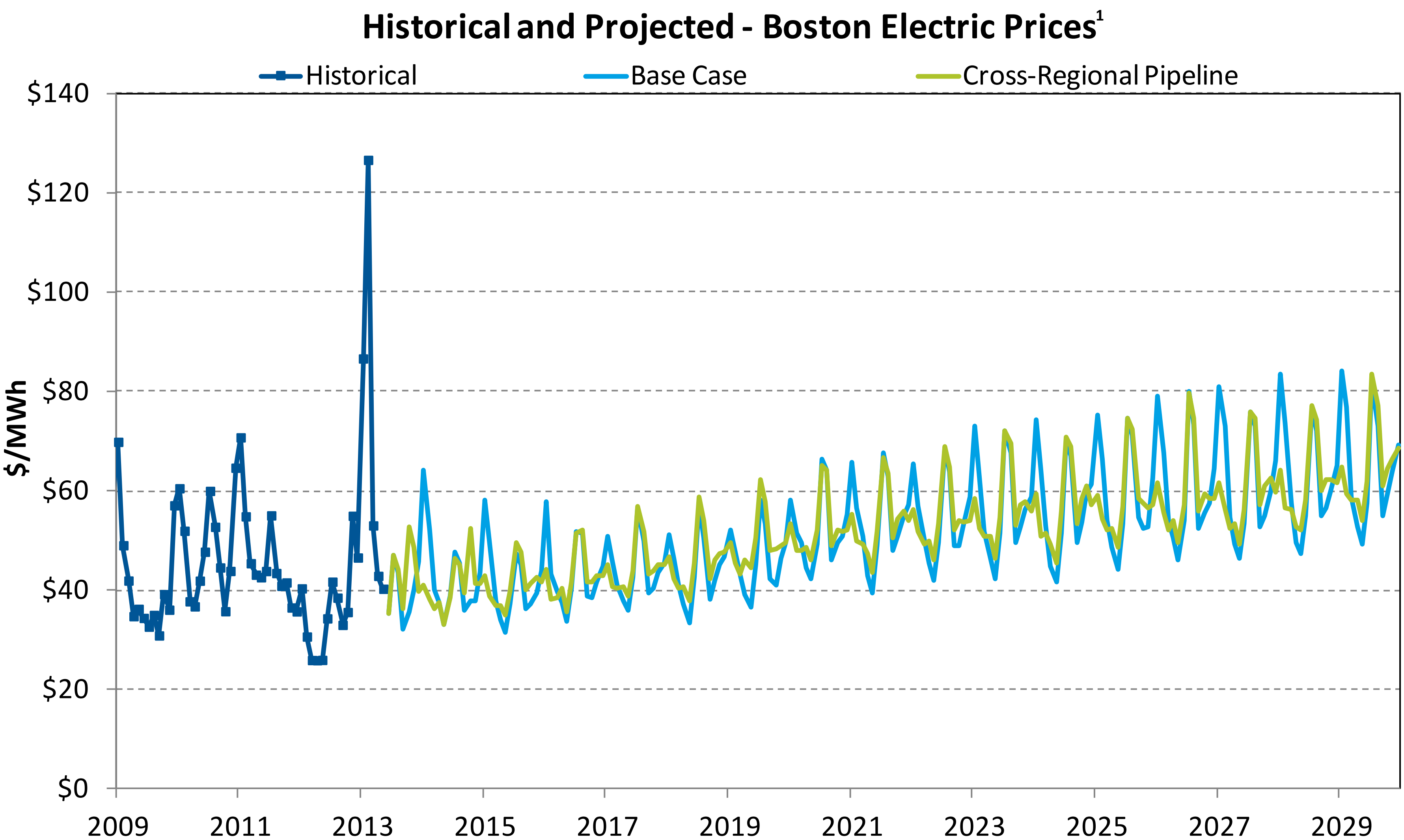
Natural Gas Basis in New England with Cross-Regional Pipeline



Projected Winter Daily Basis – Cross Regional Pipeline



Energy Price with Cross-Regional Pipeline



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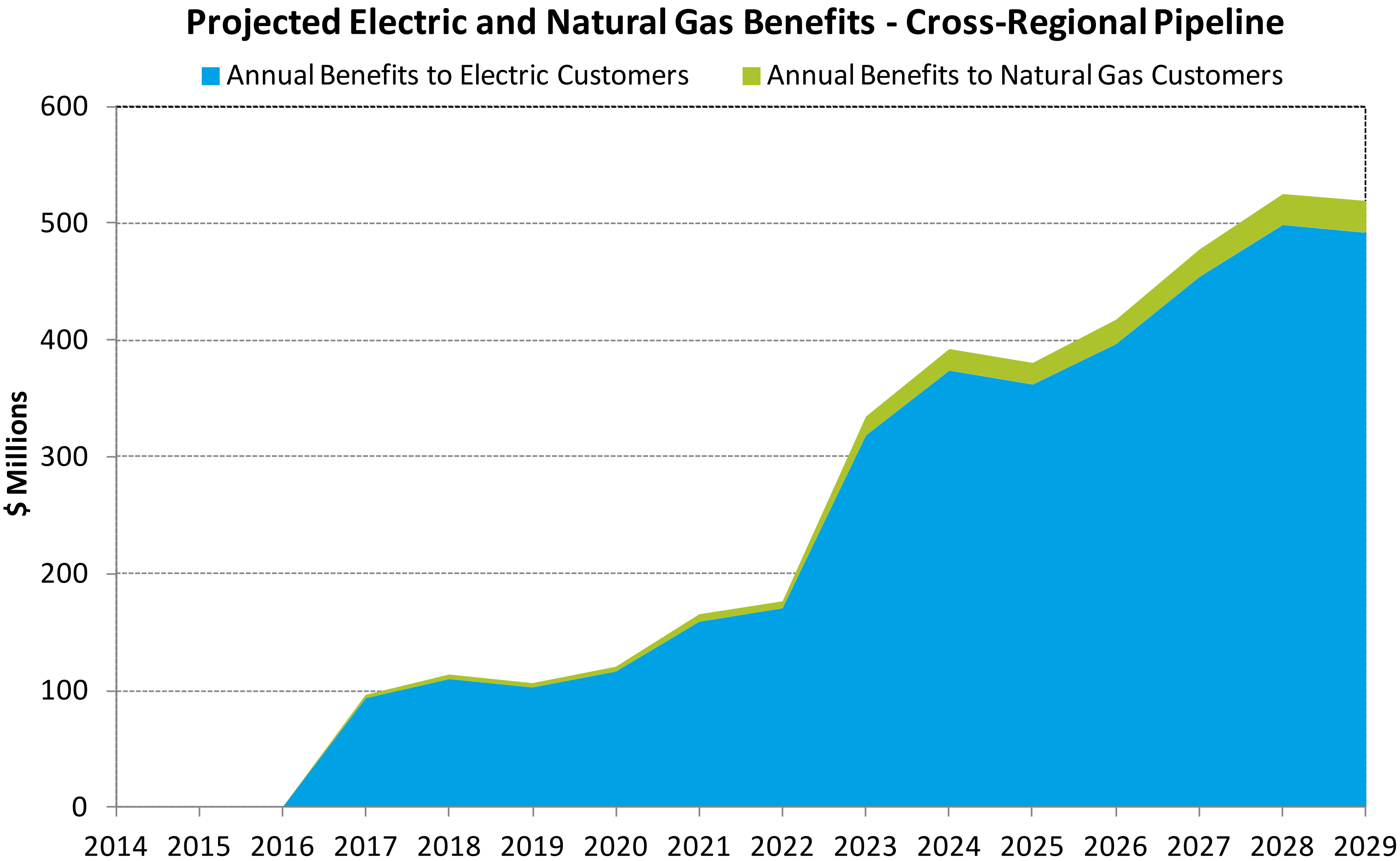
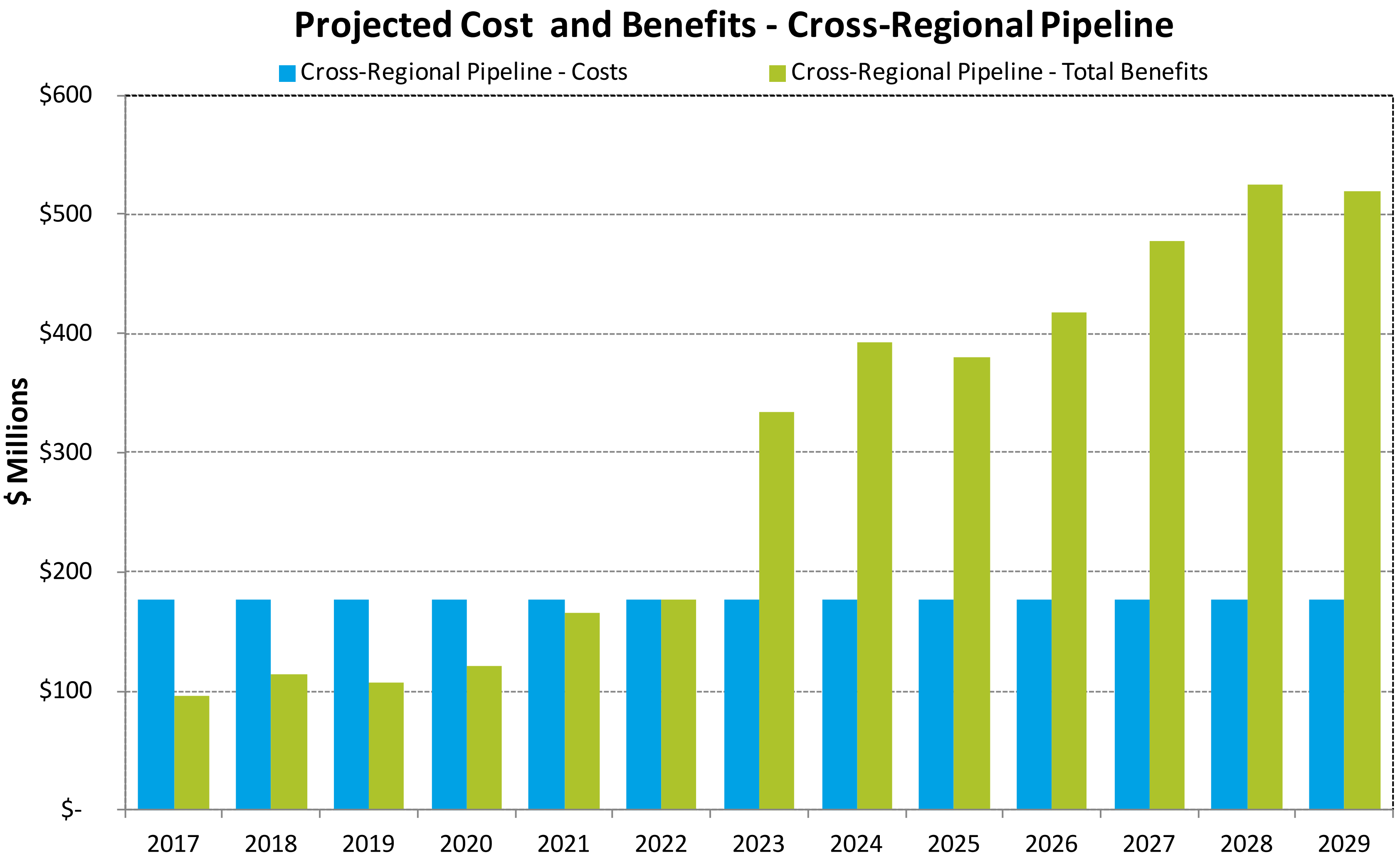
Electric and Natural Gas Customer Benefits – Cross-Regional Pipeline



Projected Cost and Benefits - Cross-Regional Pipeline



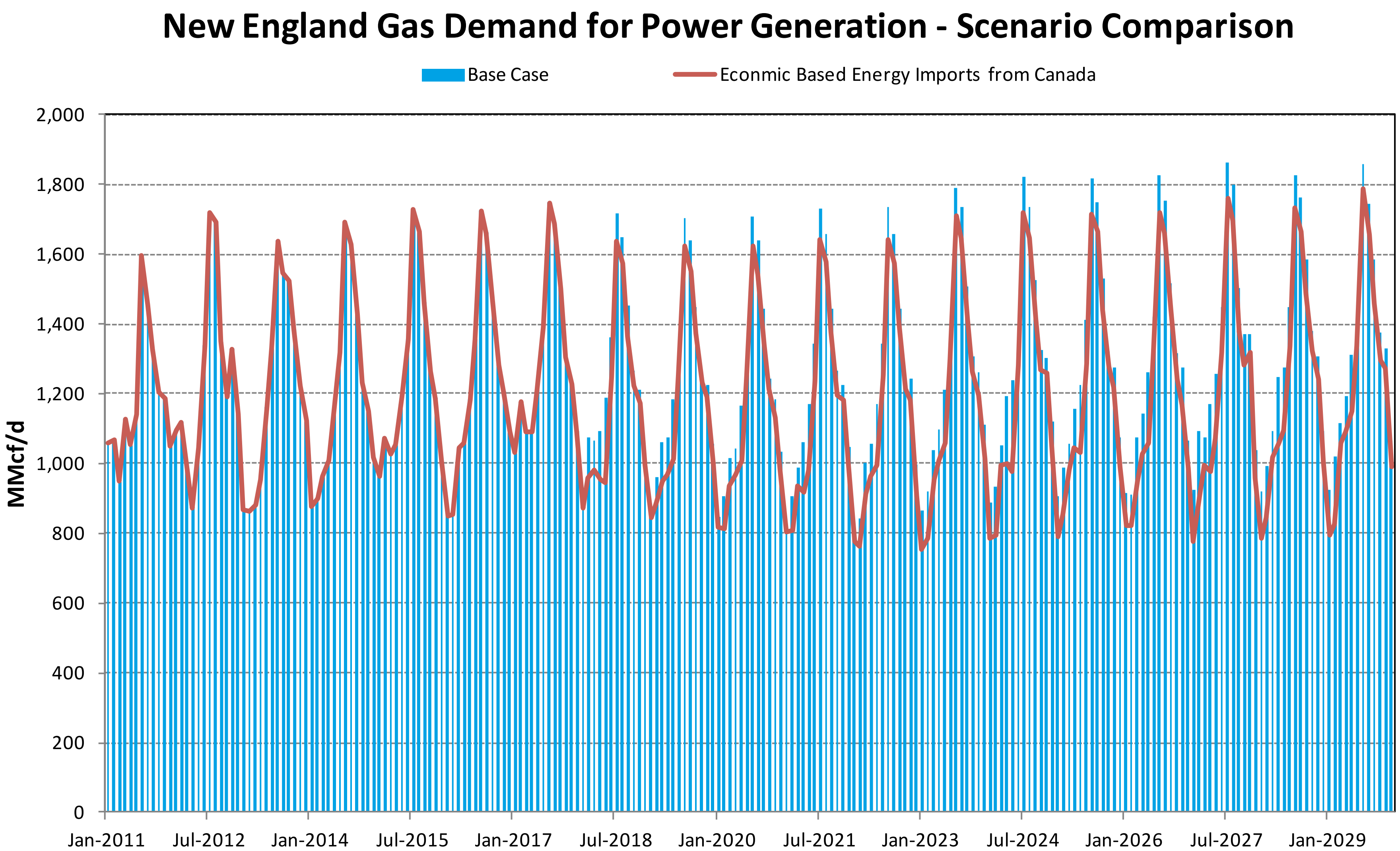
Economic Based Energy Imports

- Black & Veatch assumed an electric transmission line capable of importing 1,200 MW of hydro-electric energy from Canada to Eastern New England beginning in 2018.

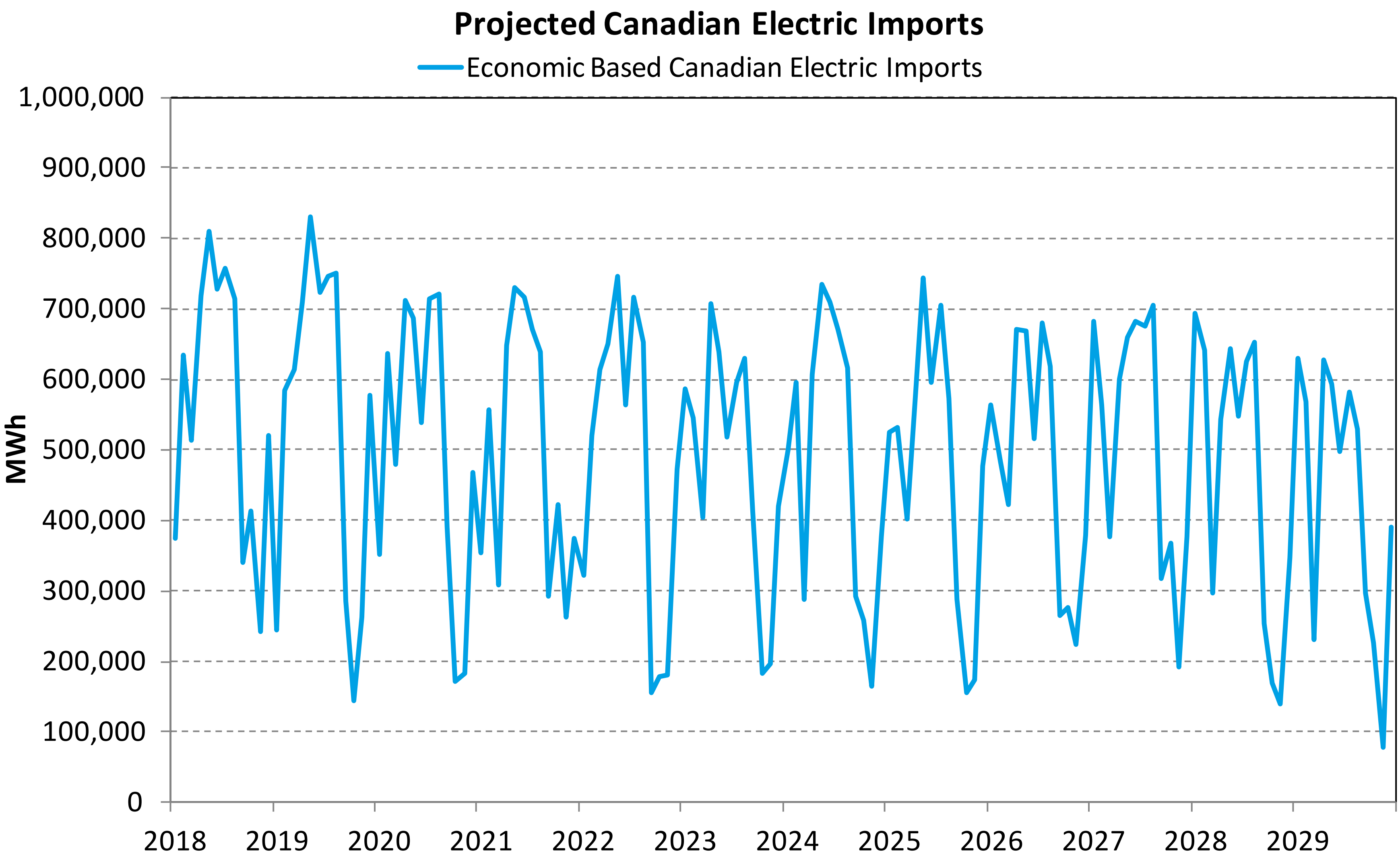
- The transmission line, originating at the Canada-U.S. border and terminating in New England, would run approximately 180 miles. Black & Veatch has estimated a construction cost of $1.1 billion based on its recent experience in constructing transmission lines in the U.S. Midwest. Levelized over twenty years, the annual cost of service for this project is estimated to range from $180 to $219 million.

- This sensitivity assumes that energy imports delivered via the transmission line are determined purely by the energy needs and price differentials between New England and alternative markets in the entire Eastern Interconnect. Therefore, when price spreads between ISO-NE and Canada present an arbitrage opportunity, energy will be imported to New England.

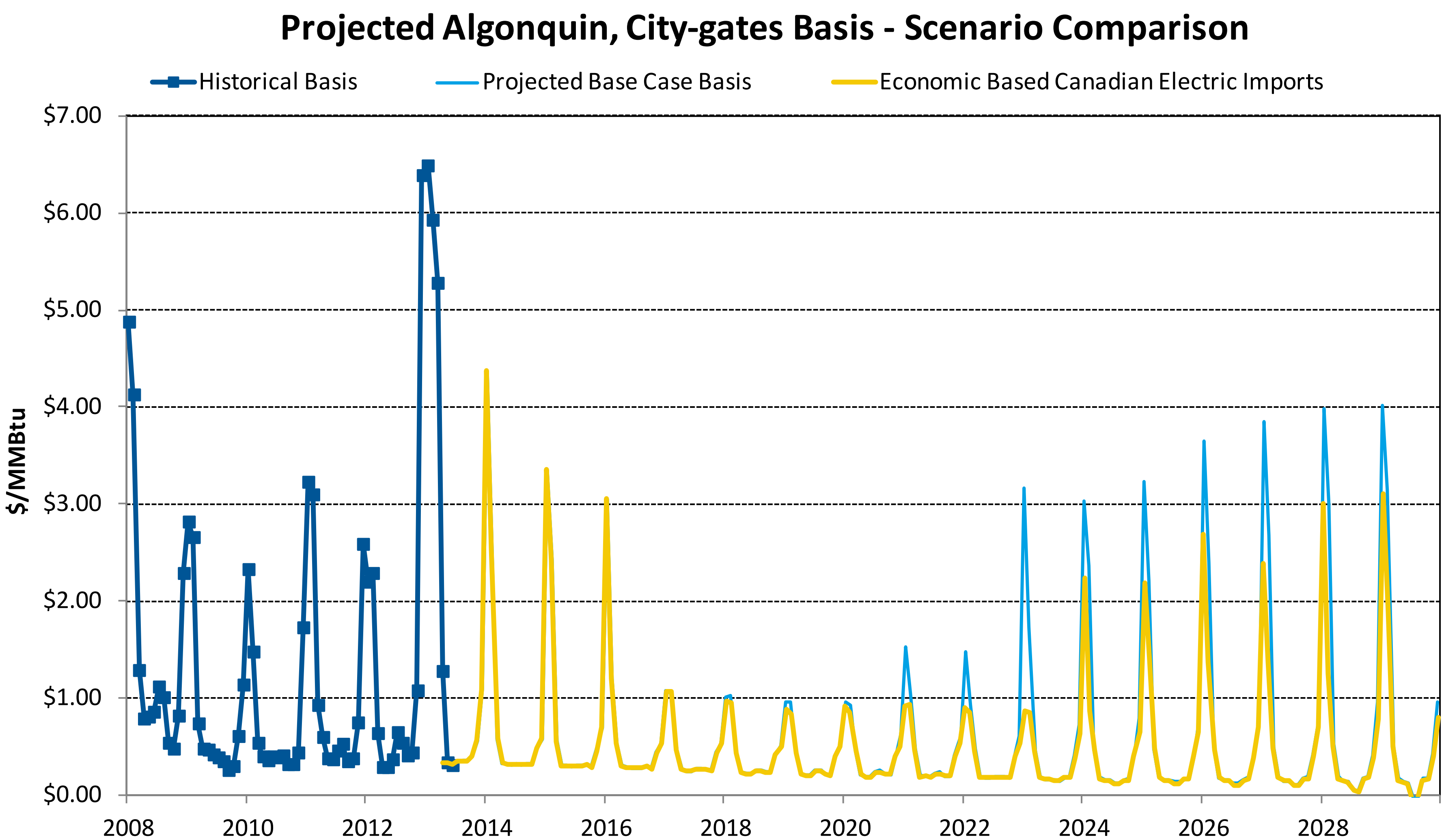
Natural Gas Demand from the Power Sector with Economic Based Energy Imports



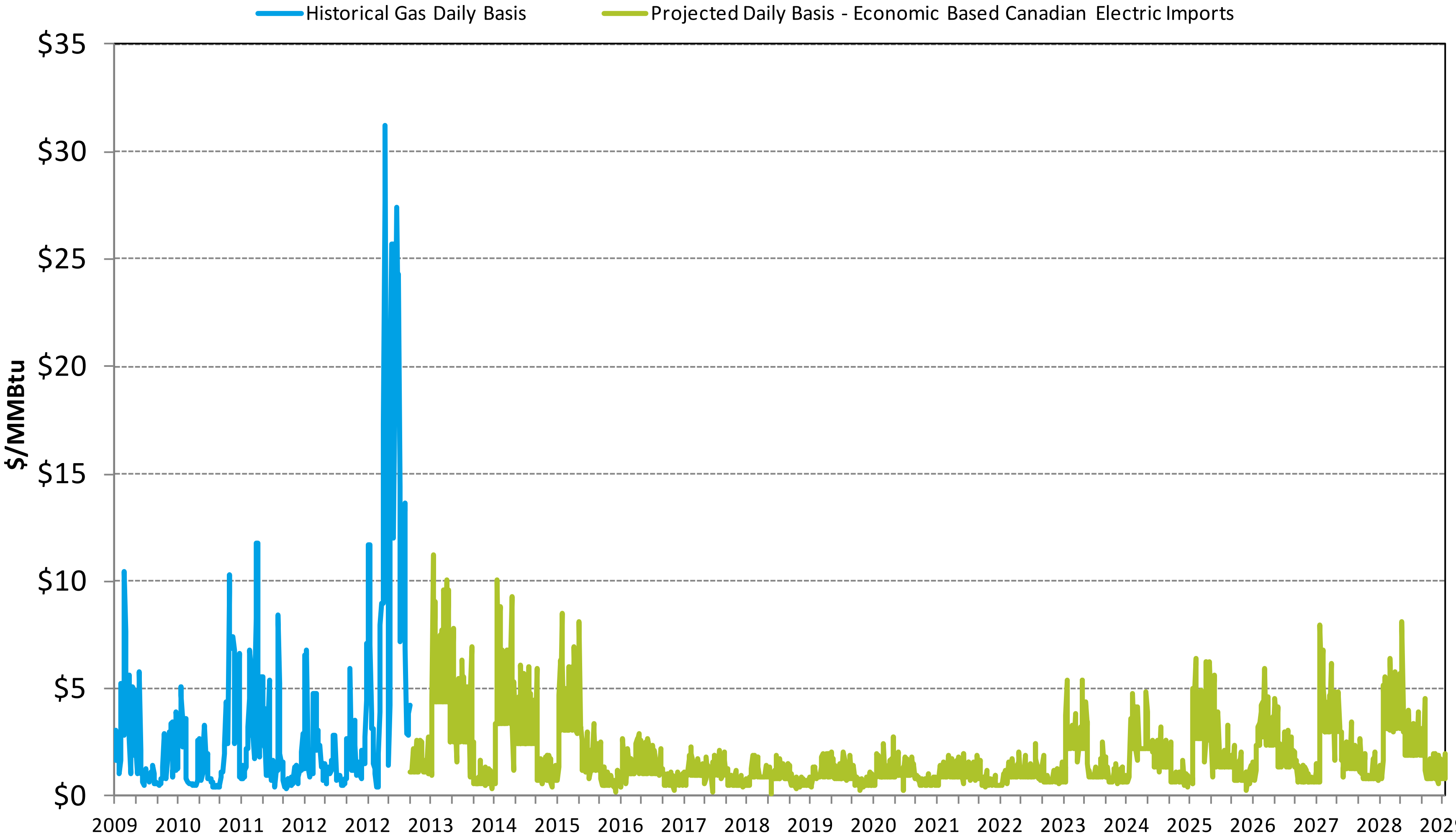
Energy Imports from Hydro Quebec



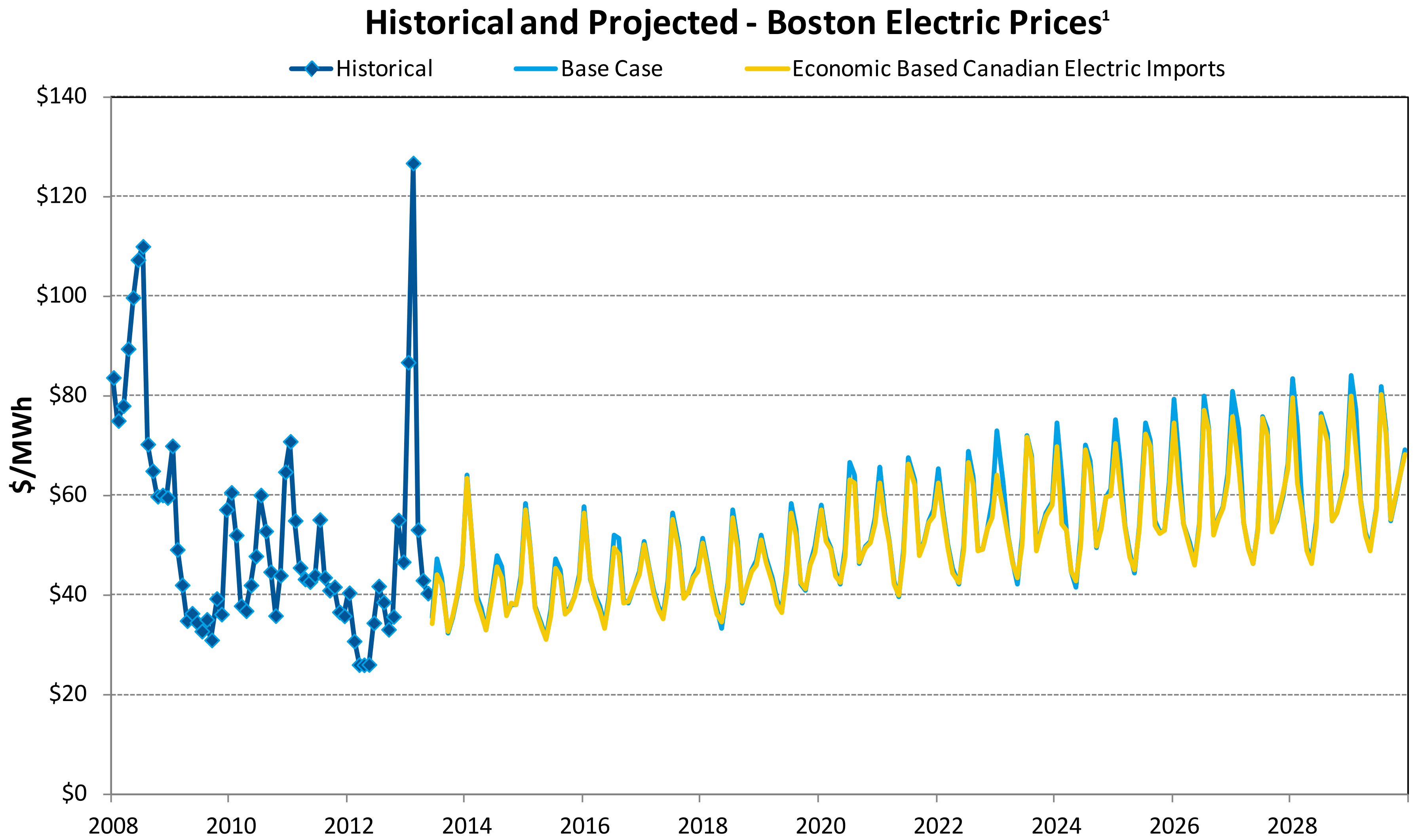
New England Natural Gas Price with Economic Based Energy Imports



Historical and Projected Daily Winter Basis – Algonquin, City-gates

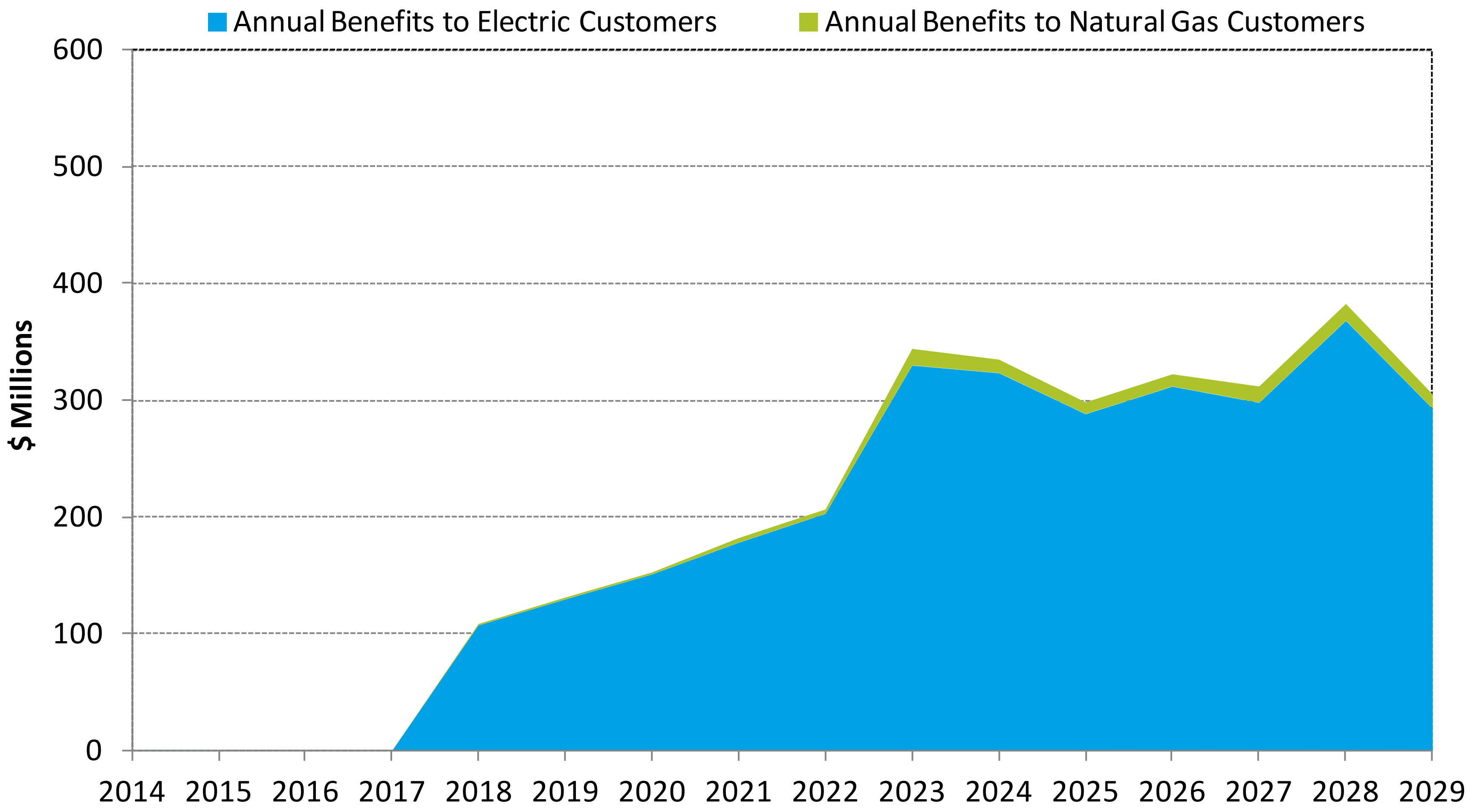


New England Energy Price with Economic Based Energy Imports

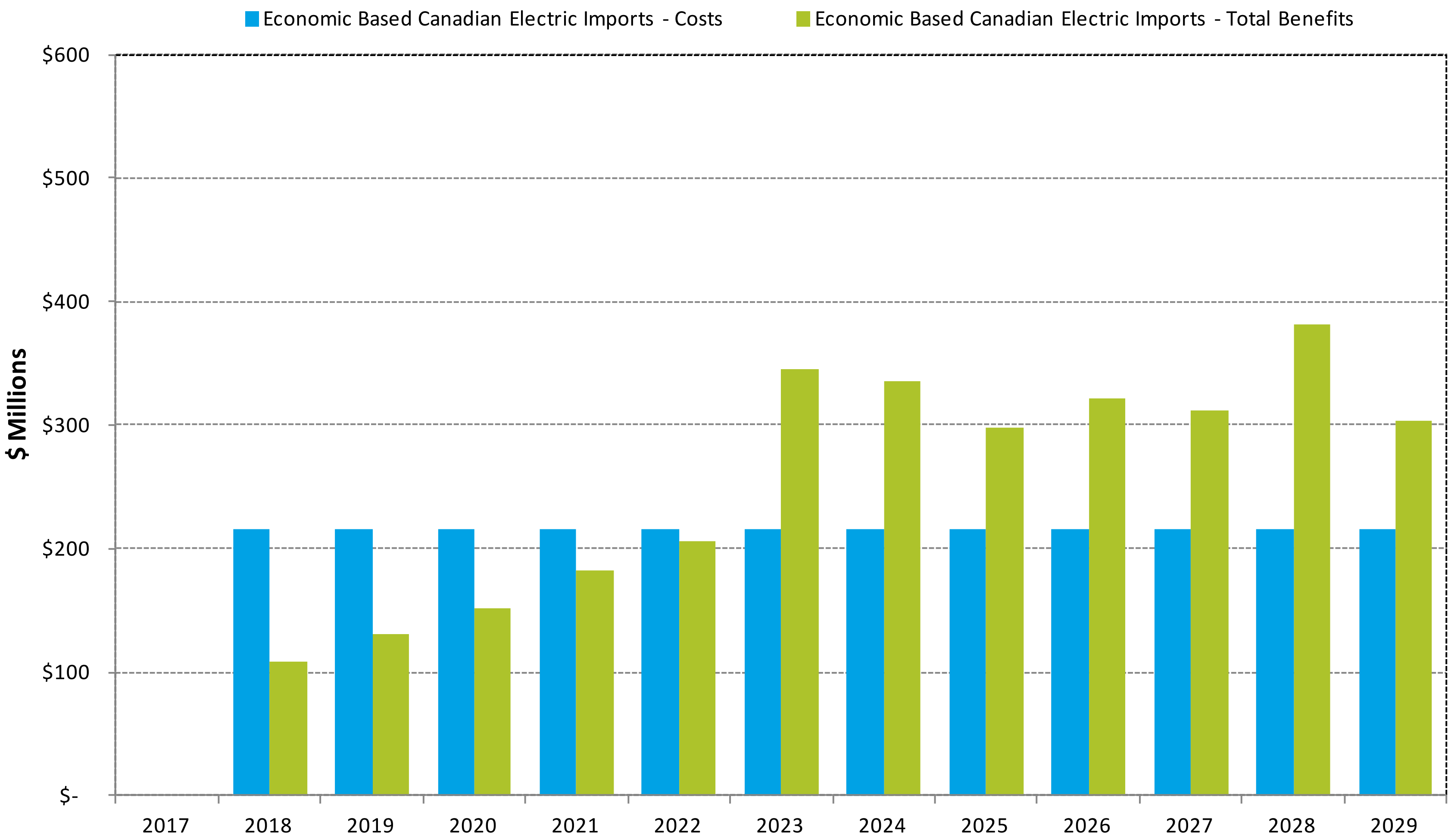


[1] For the graphic presentation of the electricity price impacts of different solutions in this report, Black & Veatch chose Boston as a corresponding electricity price location to Algonquin City-Gates. Black & Veatch selectively graphed the price impacts at other New England electricity zones to confirm that they are similar to Boston's.

Natural Gas and Energy Market Benefits with Economic Based Energy Imports



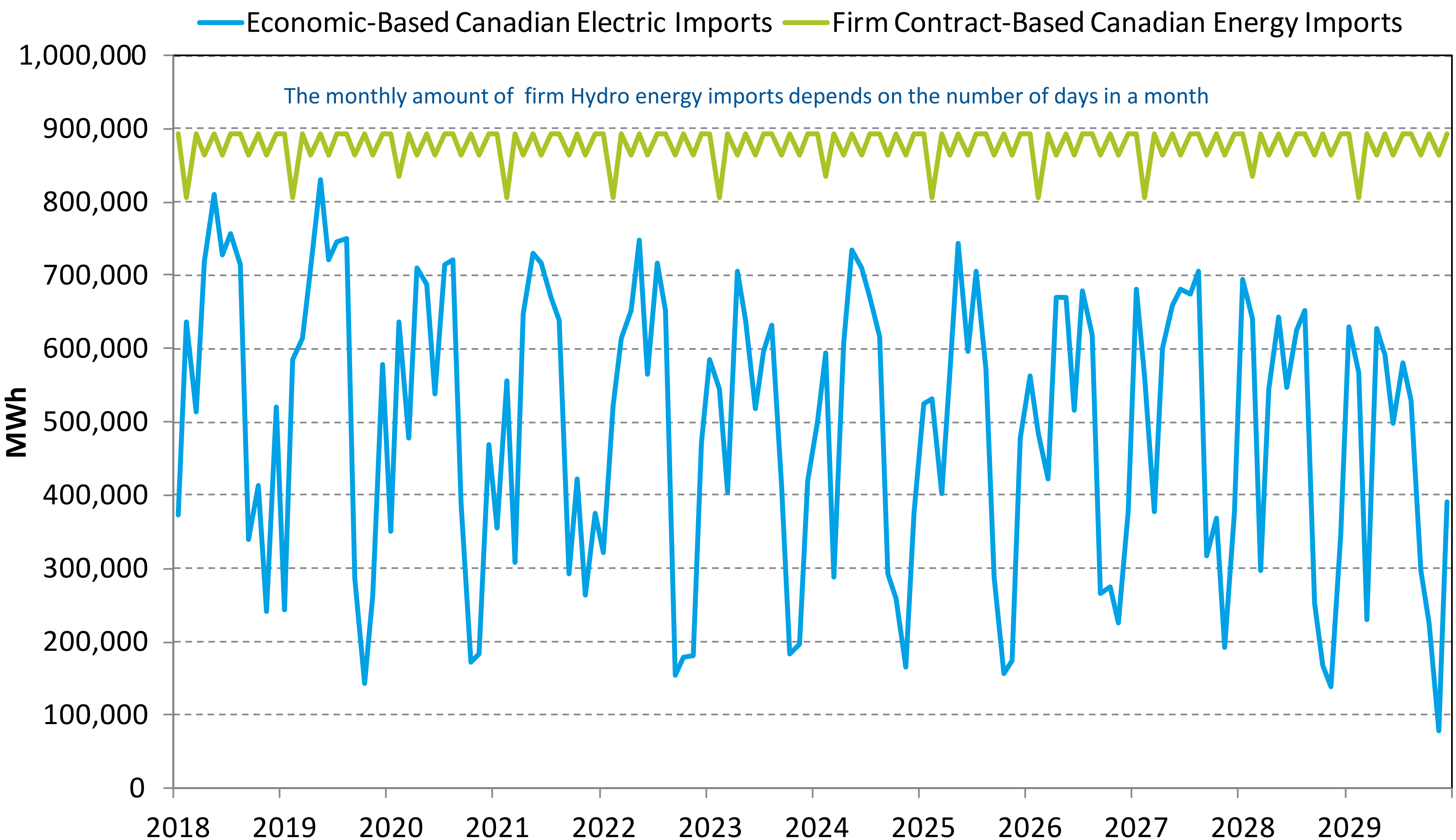
Projected Cost and Benefits with Economic Based Energy Imports



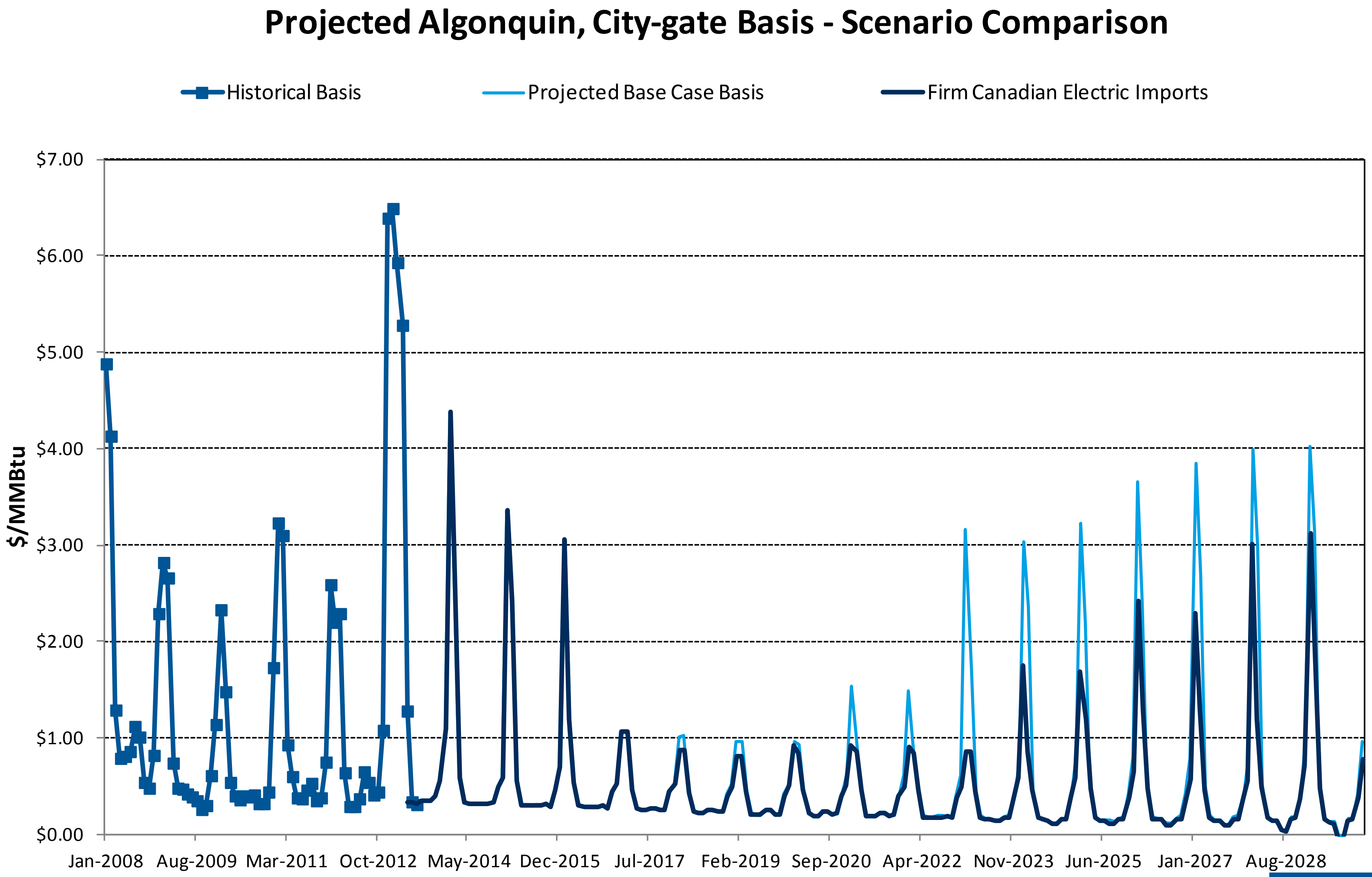
Firm-Based Energy Imports

- Black & Veatch assumed an electric transmission line capable of importing 1,200 MW of hydro-electric energy from Canada to Eastern New England beginning in 2018.
- The level of energy imported by the transmission line described above is guaranteed through a contractual agreement with Hydro Quebec.
- In addition to the electric transmission line, Black & Veatch assumed the expansion and/or construction of generation facilities (potential dam construction) and a firm contract for 1,200 MW for every hour of the day, 365 days a year starting in 2018.
- The construction of power-generation facilities in Hydro Quebec would cost $170 million per year in addition to the previously stated cost of the transmission line.

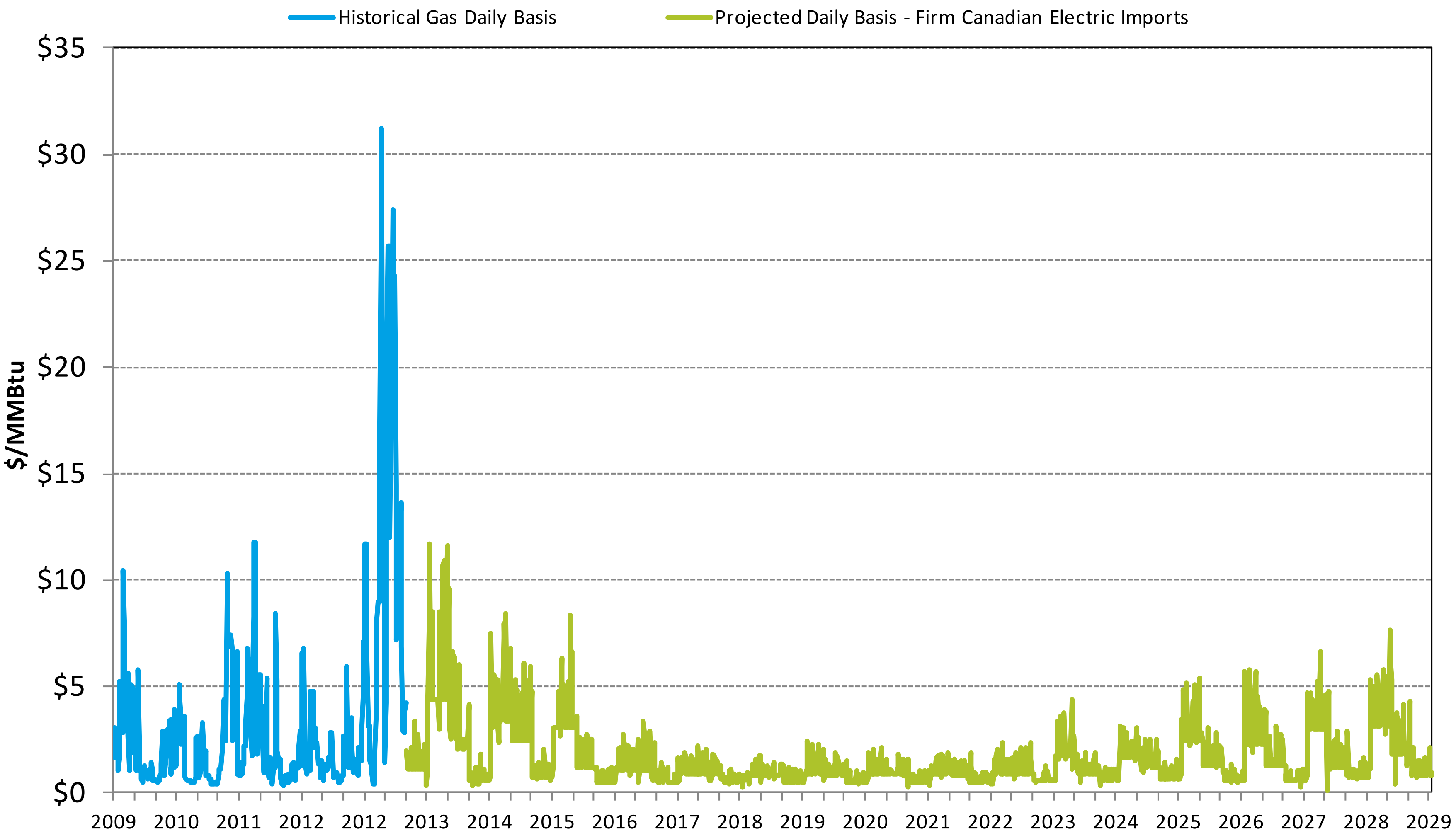
Energy Imports from Hydro Quebec



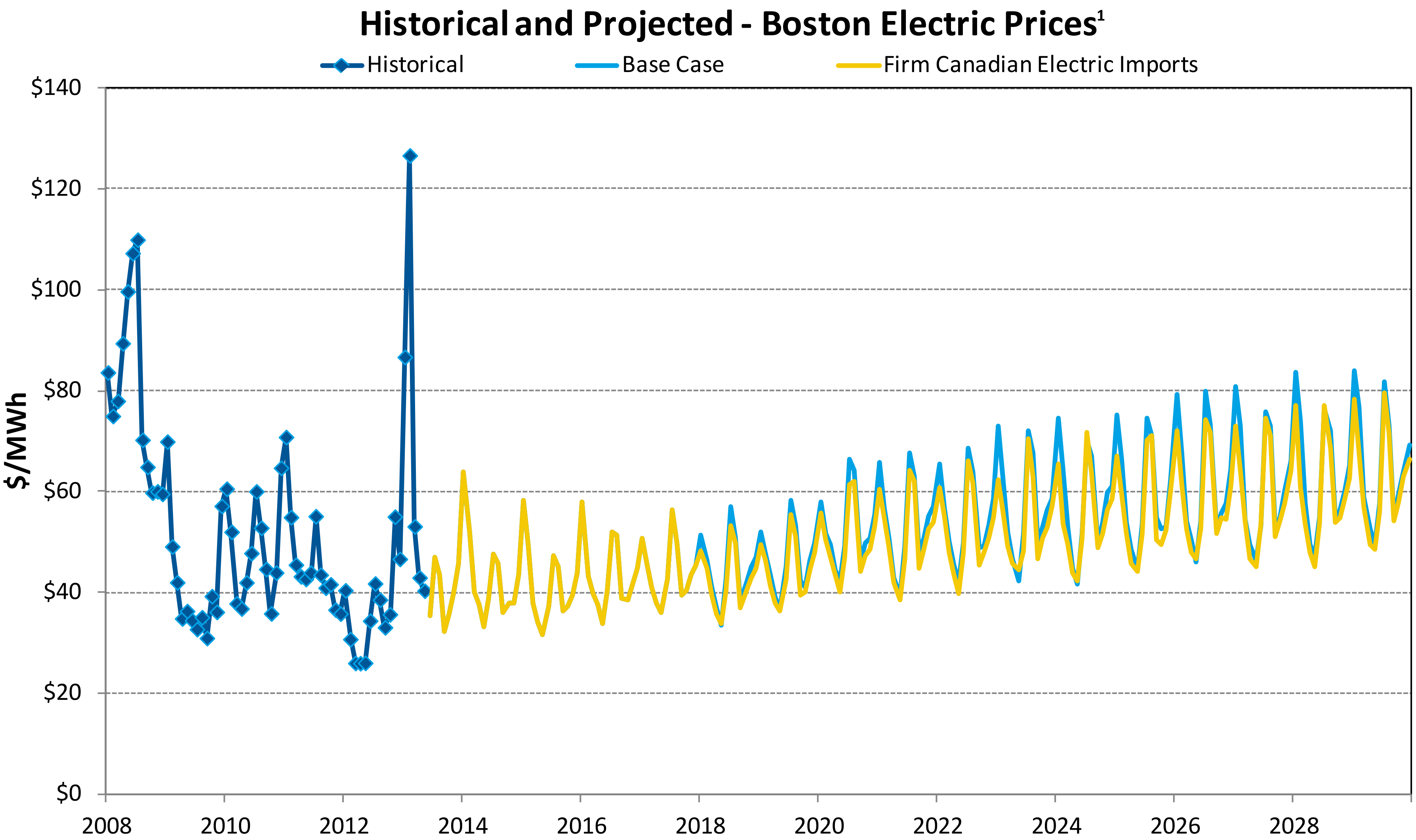
New England Natural Gas Price with Firm-Based Energy Imports



Historical and Projected Daily Winter Basis – Algonquin, City-gates



New England Energy Price with Firm-Based Energy Imports



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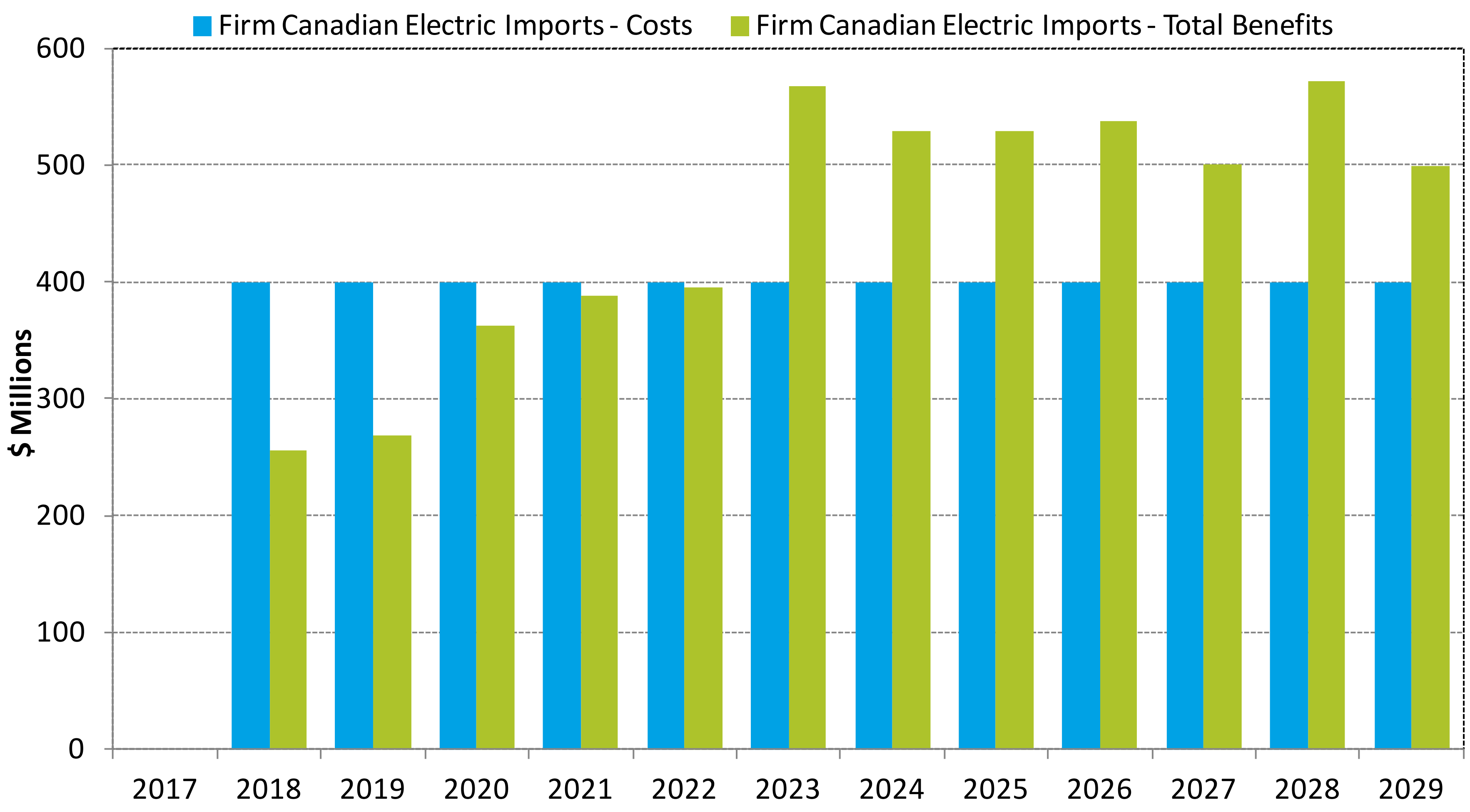
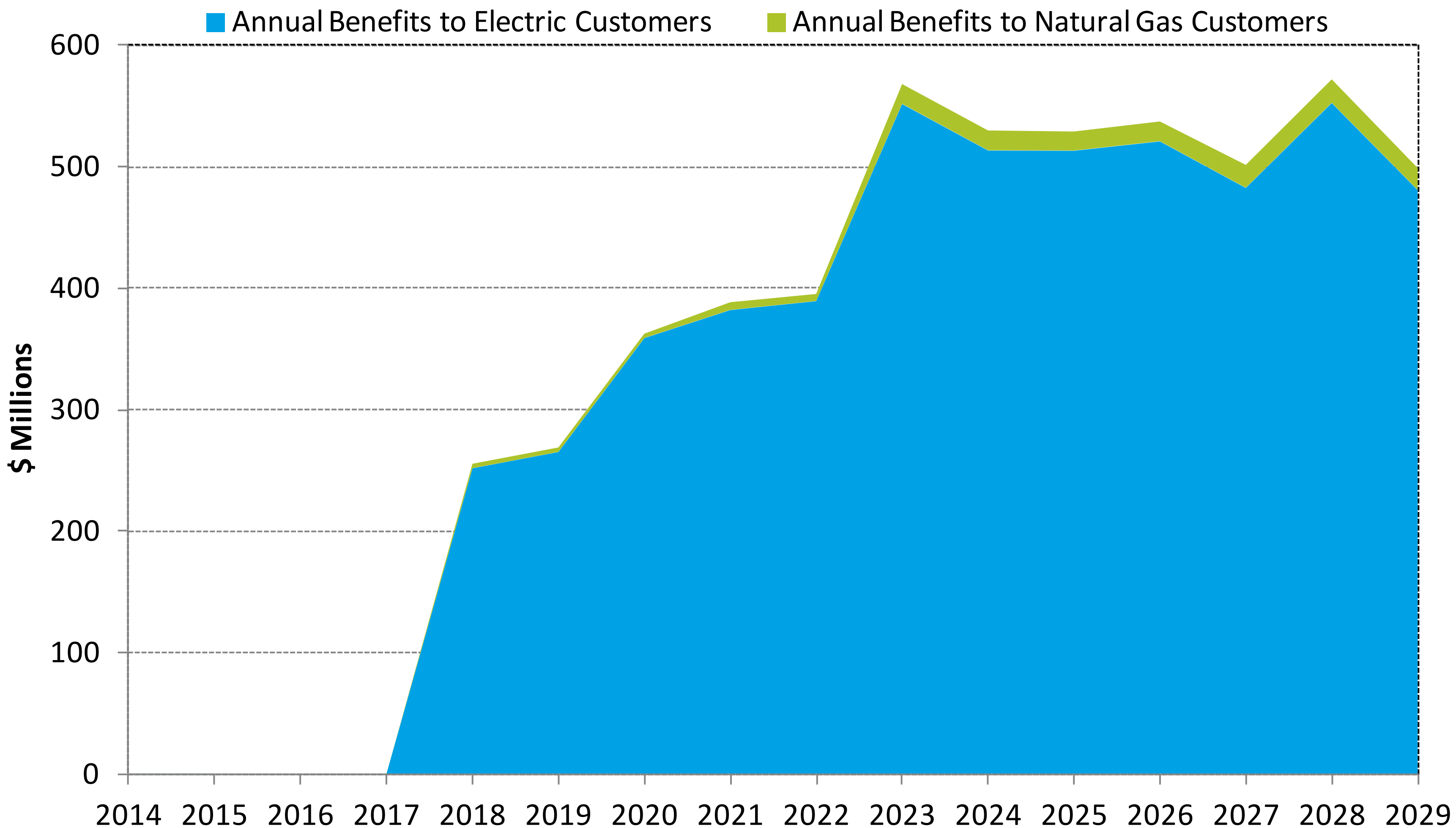
Natural Gas and Electric Market Benefits with Firm-Based Energy Imports



Projected Cost and Benefits with Firm-Based Energy Imports



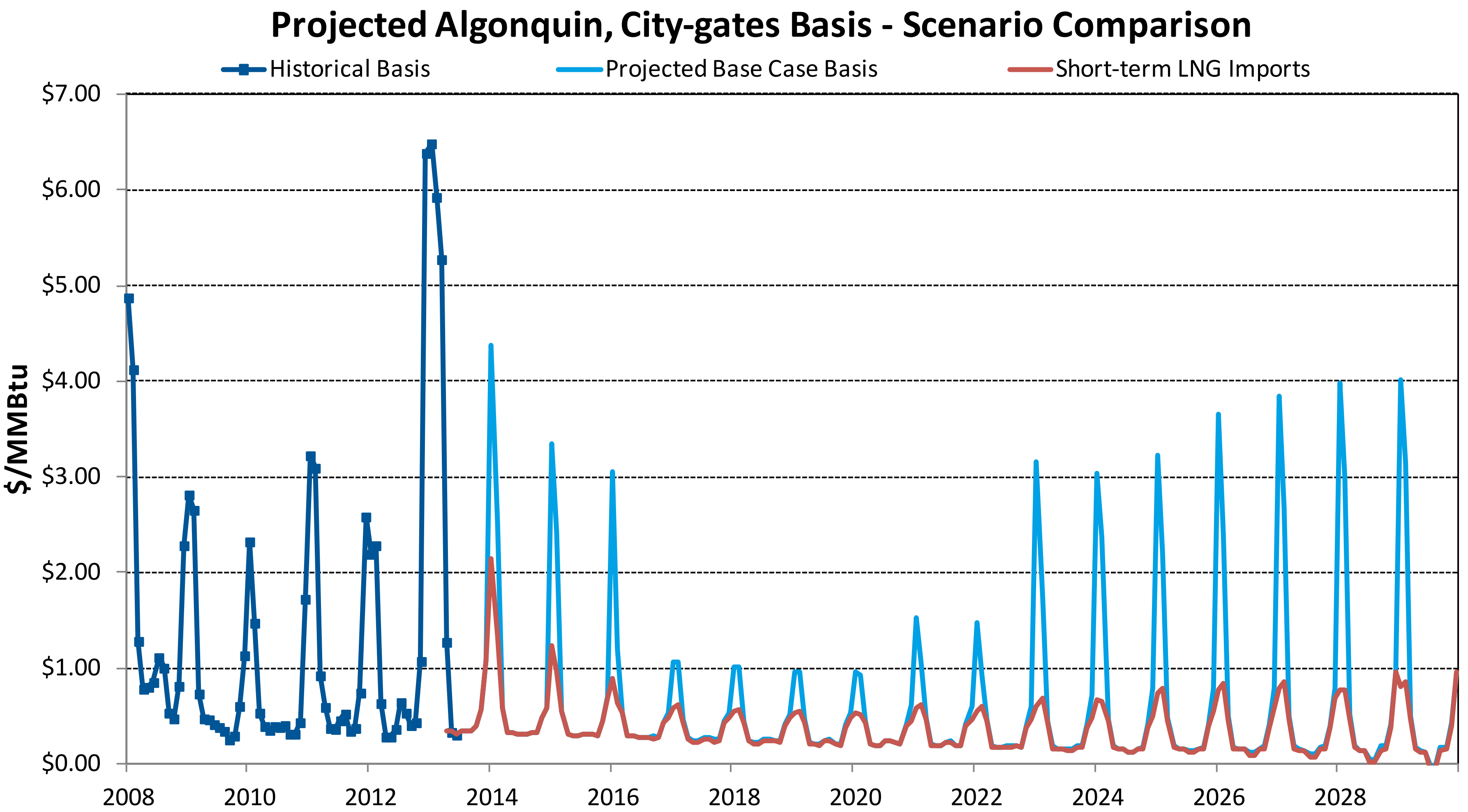
Presentation Outline

- **Executive Summary**
- **Base Case Scenario Assumptions**
- **Base Case – No Incremental Infrastructure Results**
- **Long-term Infrastructure Solution Sensitivities**
  - Base Case – With Cross-Regional Pipeline
  - Base Case – With Economic Based Energy Imports
  - Base Case – With Firm-Based Energy Imports
- **Short-term Infrastructure Solution Sensitivities**
  - Base Case – With Short-term LNG Imports
  - Base Case – With Dual-Fuel Generation

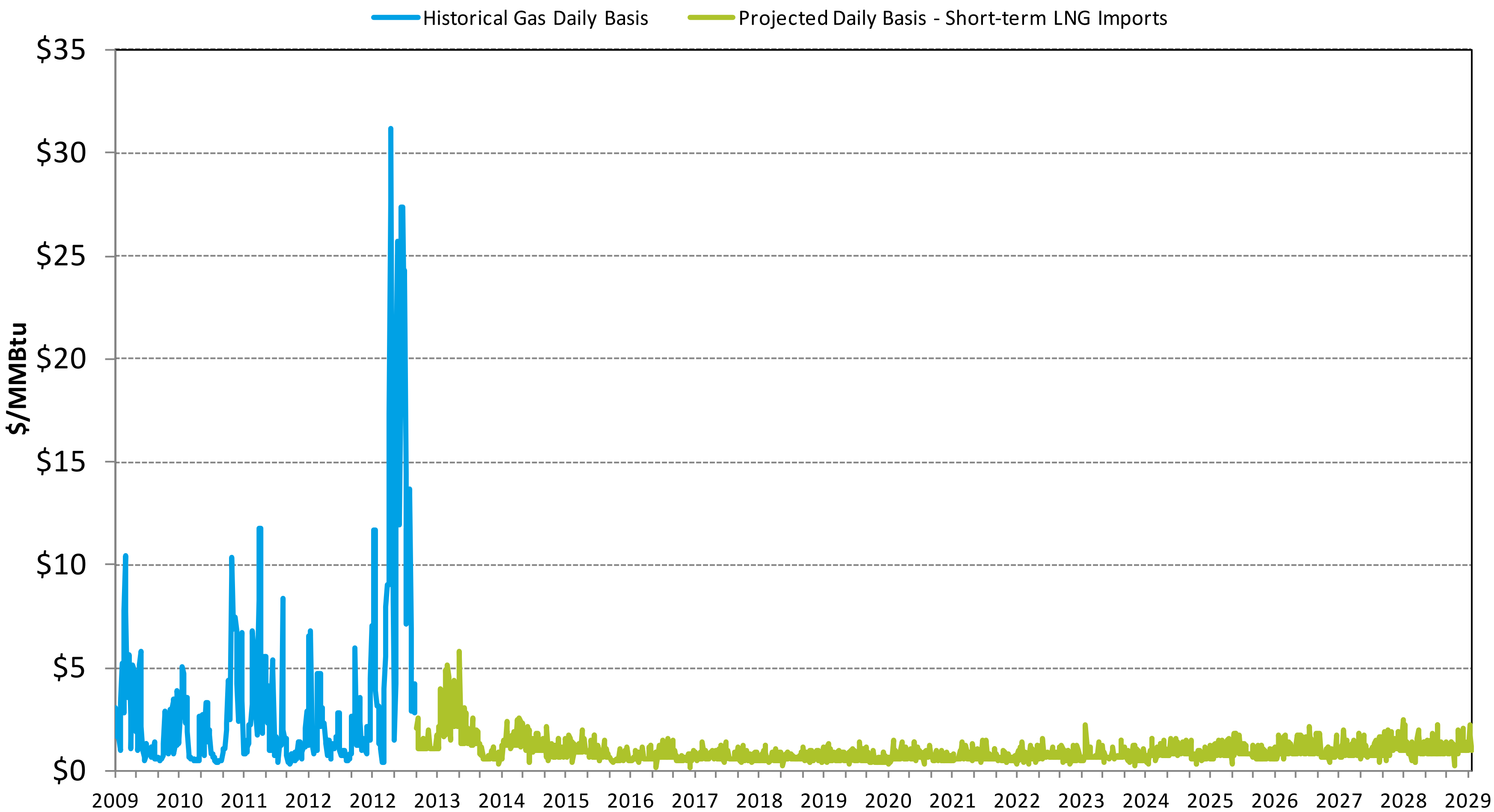
LNG Import Assumptions – Volume and Price

- Black & Veatch assumes that an additional 300 MMcf/d of LNG imports to the Canaport and the Everett LNG terminals, during the peak winter months of January and February. This represents 18 Bcf of additional volume, 4 – 5 additional cargoes.
  - Canaport can accommodate the additional cargoes with 9.9 Bcf storage and 730 MMcf/d Maritimes and Northeast Pipeline capacity.
  - Everett and other New England coast terminals can accommodate this with 3.5 Bcf storage and interconnects with Tennessee and Algonquin pipelines.
- This analysis assumes that incremental LNG imports will be priced at $15/MMBtu in 2014 and steadily increase at around 1.0% annually over the analysis period, consistent with Black & Veatch's projected oil price trajectory.
- The delivered cost of additional LNG cargoes is expected to be strongly tied to oil-indexed global LNG prices, which are priced significantly higher than current wholesale prices at Algonquin City-Gates.
- As the growth of LNG liquefaction capacity outpaces global LNG demand, the future oil indexation of global LNG prices may weaken, thus having the effect of reducing global LNG prices for spot cargoes into New England. Black & Veatch did not incorporate the latter assumption for the analysis.

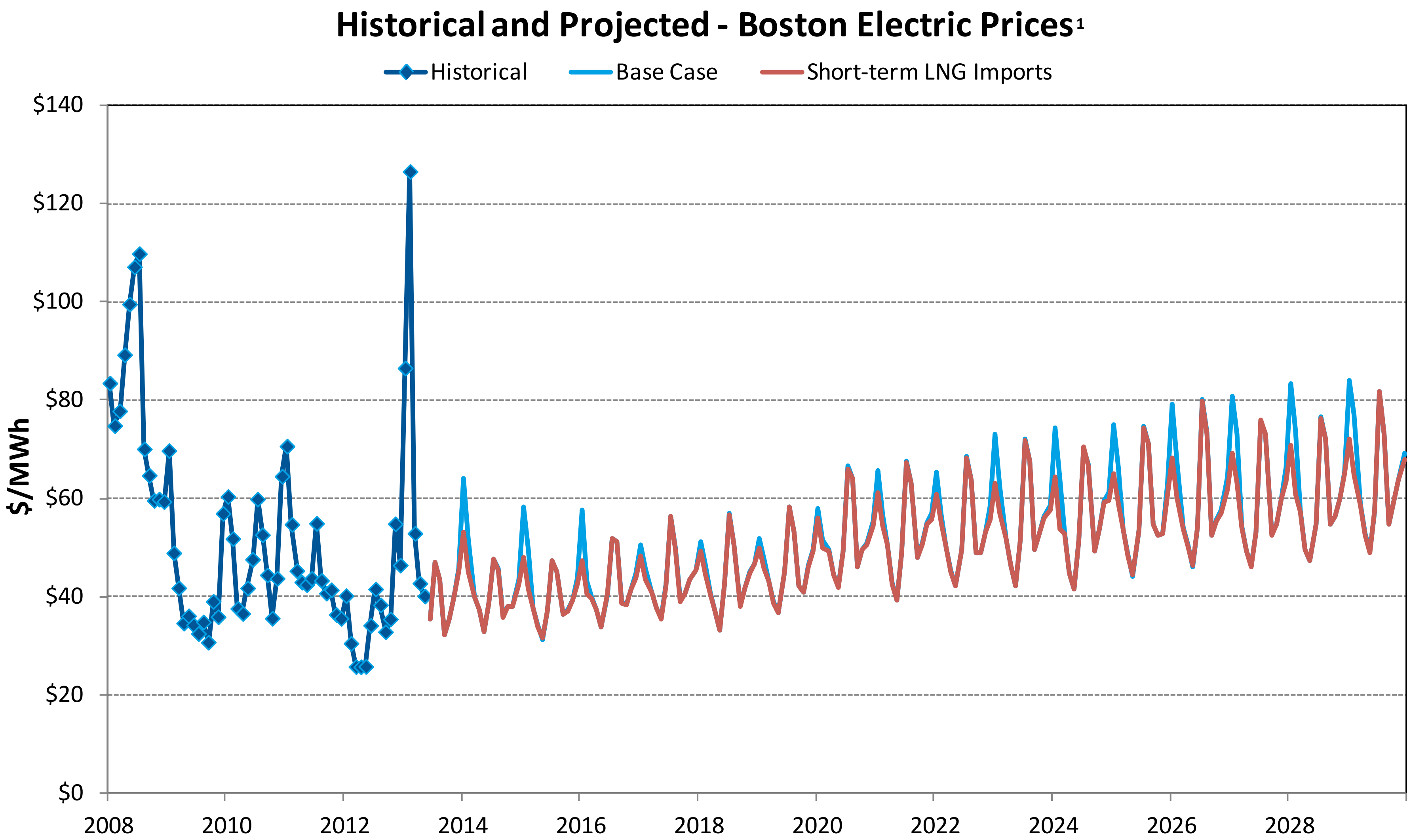
New England Basis with LNG Imports



Historical and Projected Daily Winter Basis – Algonquin, City-gates



Energy Price with Short-term LNG Imports



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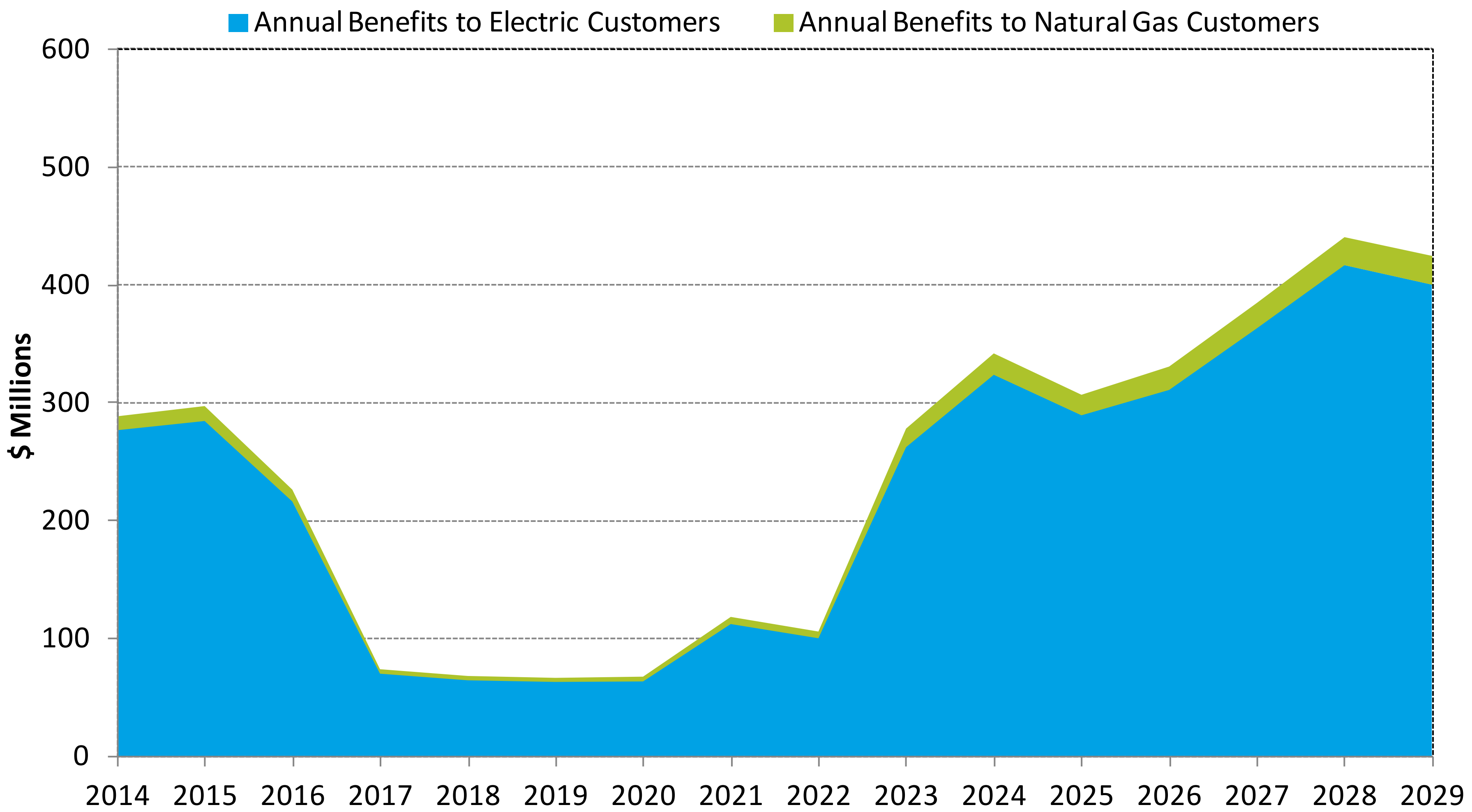
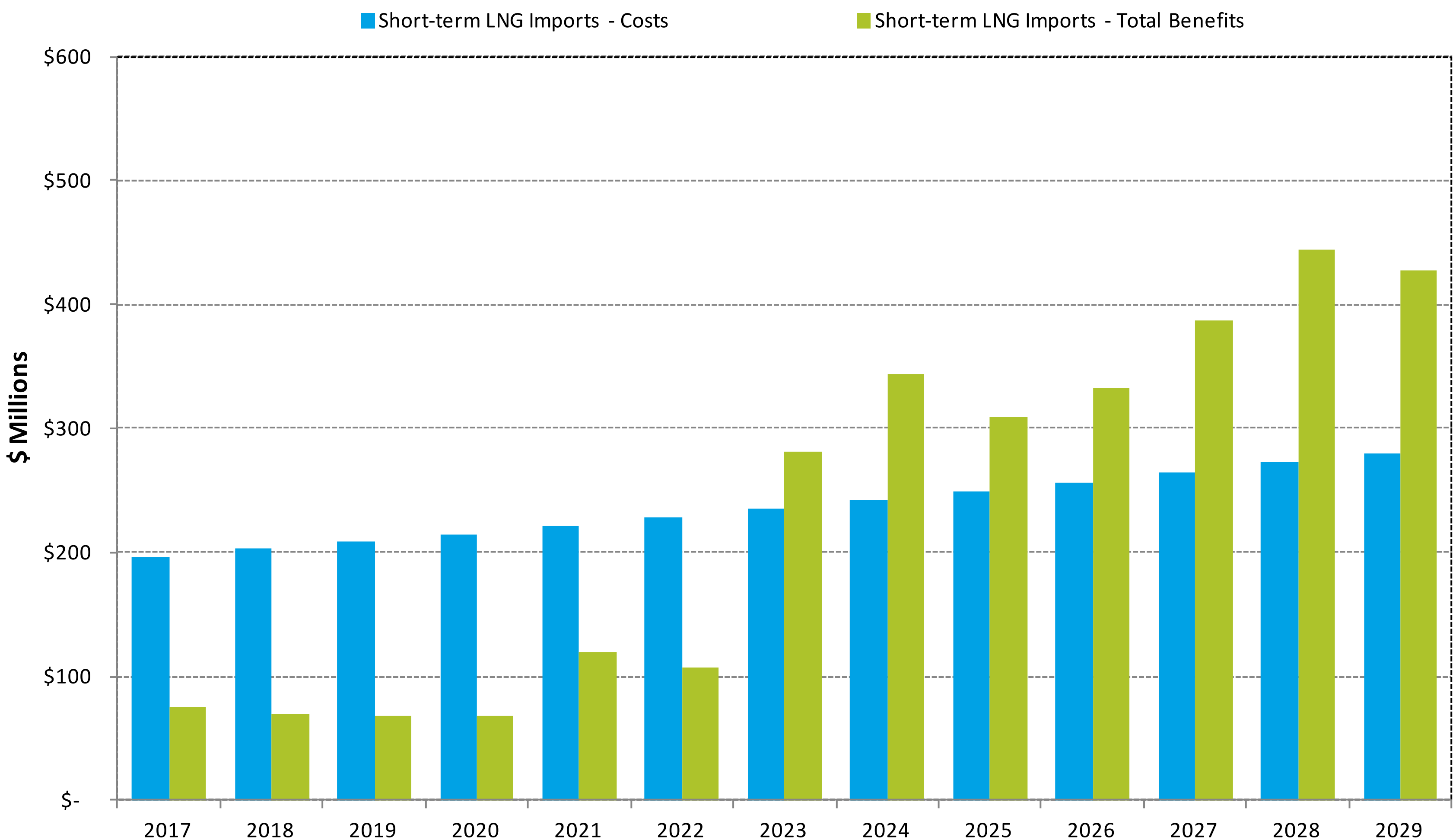
Projected Electric and Natural Gas Customer Benefits - Short-term LNG Imports



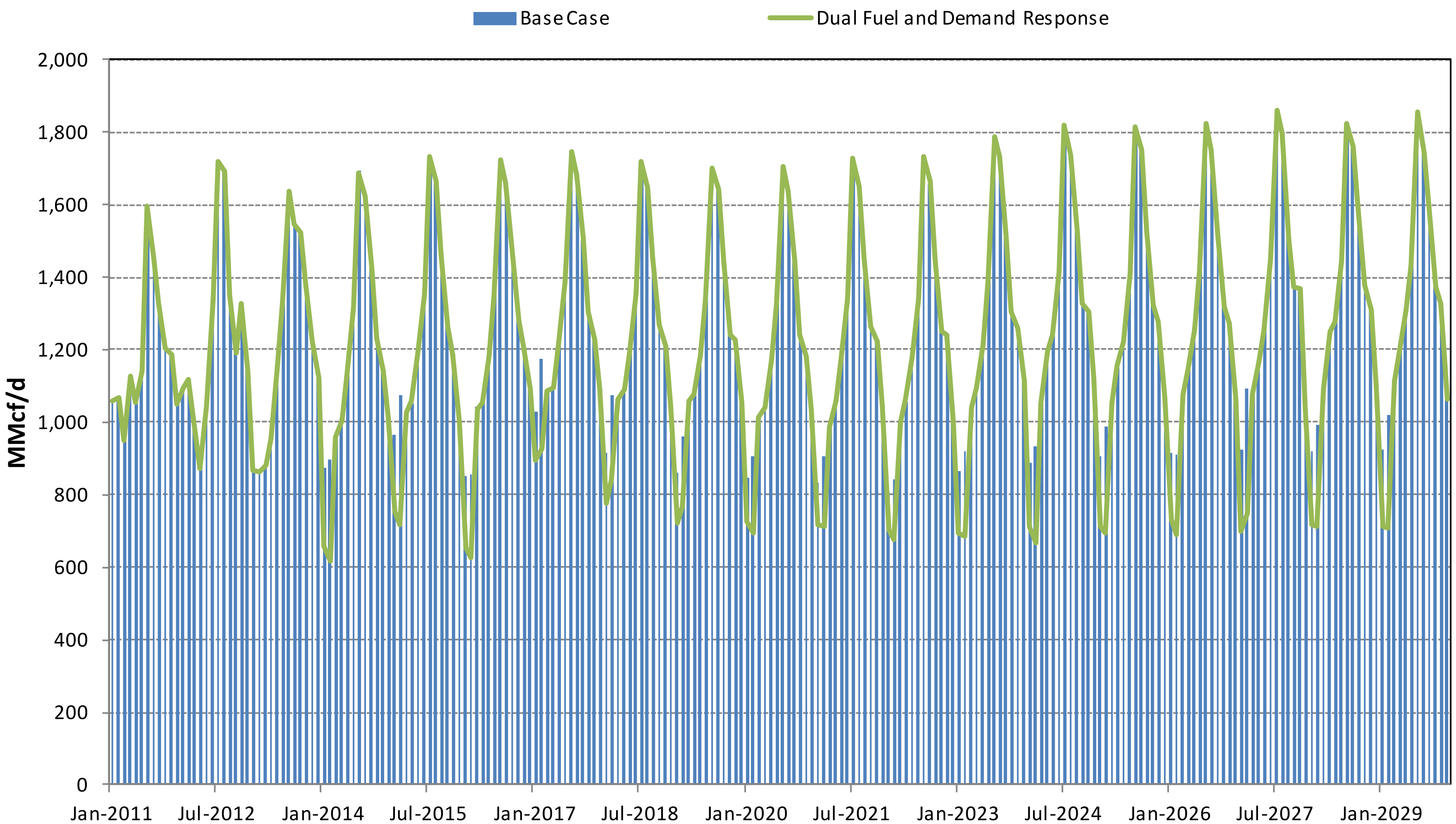
Projected Cost and Benefits – Short-term LNG Imports



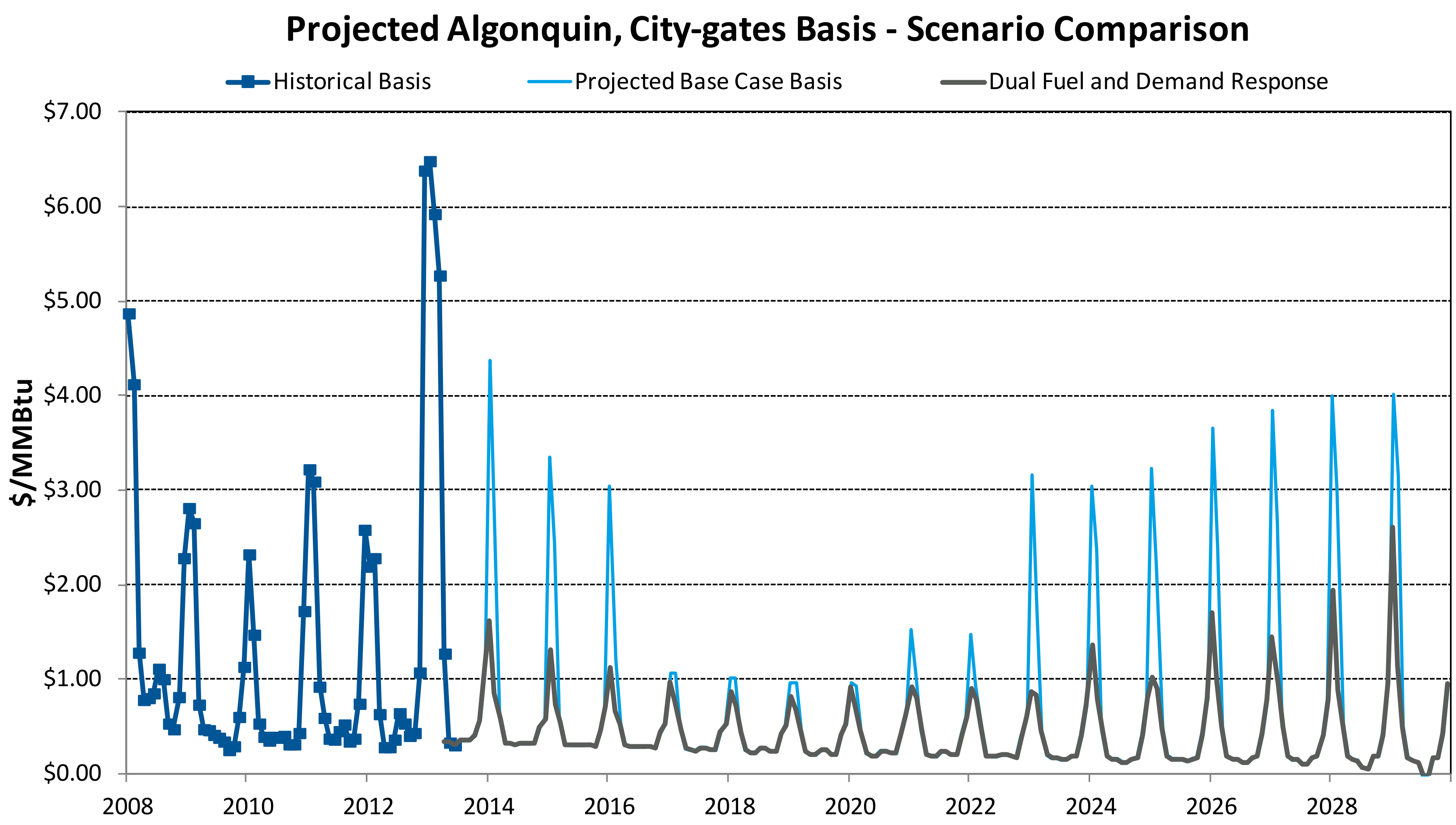
Dual-Fuel Generation and Demand Response Assumptions

- An additional 2.3 million MWh of fuel-oil-fired generation to be dispatched during peak winter months, regardless of cost.
- Dual-fuel fuel-oil based generation is assumed to be "out of merit" units that will be dispatched during peak winter months.
- Currently, the New England power generation fleet has approximately 10,200 MW of dual fuel capacity that can be dispatched into the transmission grid.
- The associated costs of out-of-merit dispatching of fuel-oil-based generation are calculated as the "uplift costs" paid to power generators that would make them financially indifferent between using fuel oil or natural gas to generate electricity.
- Additional demand response was made available to dispatch into the market, albeit at prices significantly higher than the projected market clearing price.

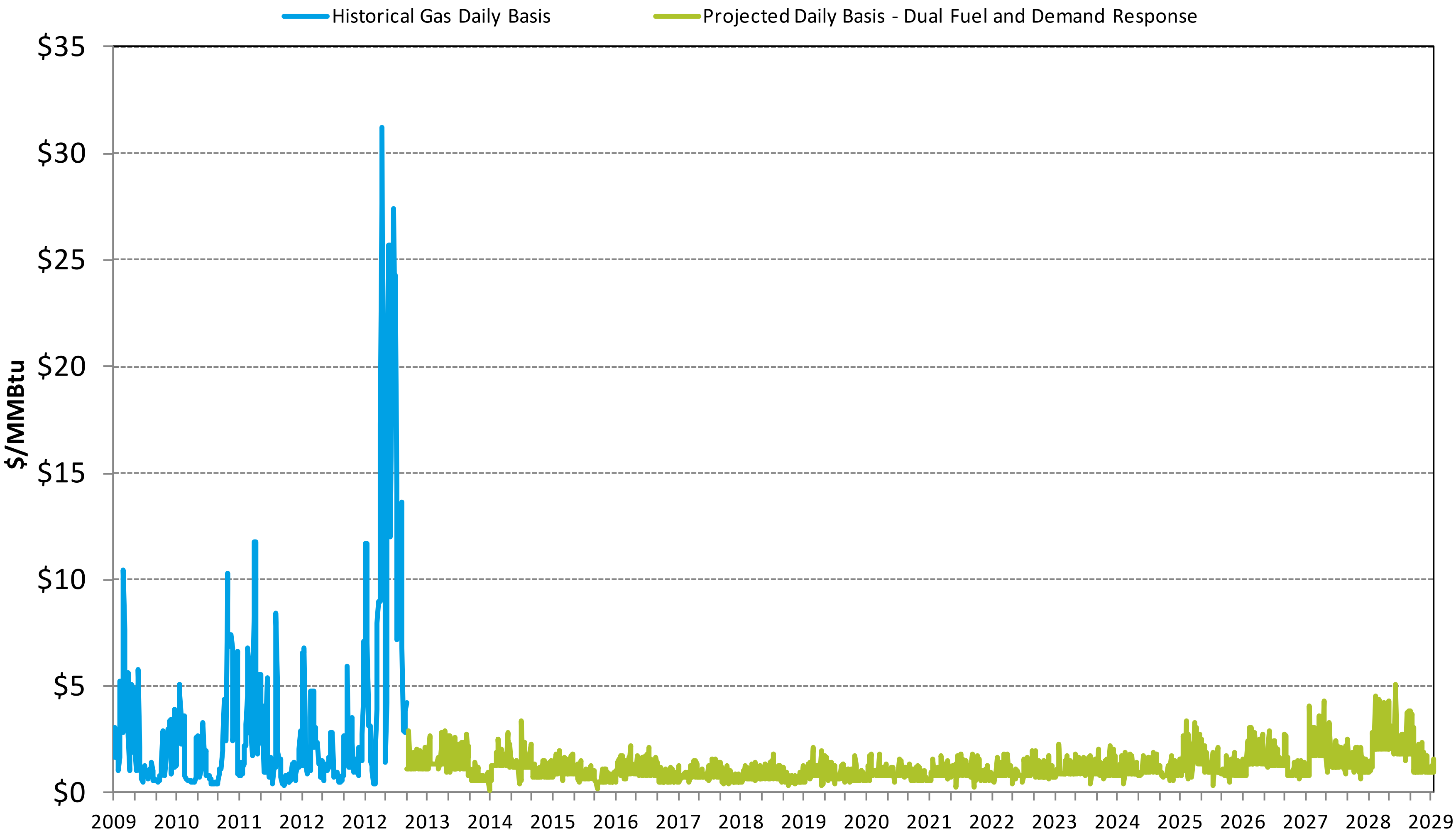
New England Natural Gas Demand from the Power Sector with Dual-Fuel Generation and Demand Response



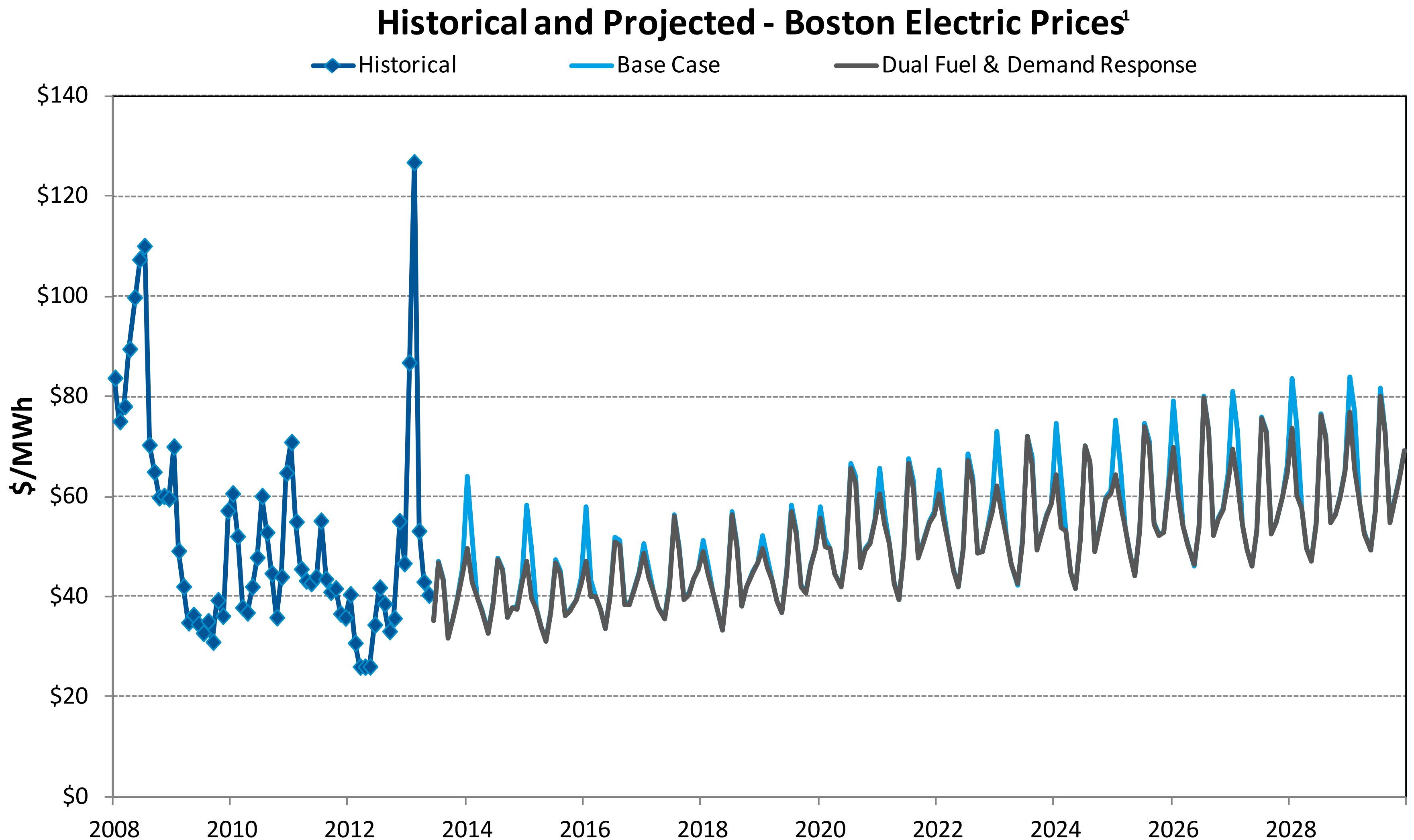
New England Natural Gas Price with Dual-Fuel Generation and Demand Response



Historical and Projected Daily Winter Basis – Algonquin, City-gates



New England Energy Price with Dual-Fuel Generation and Demand Response



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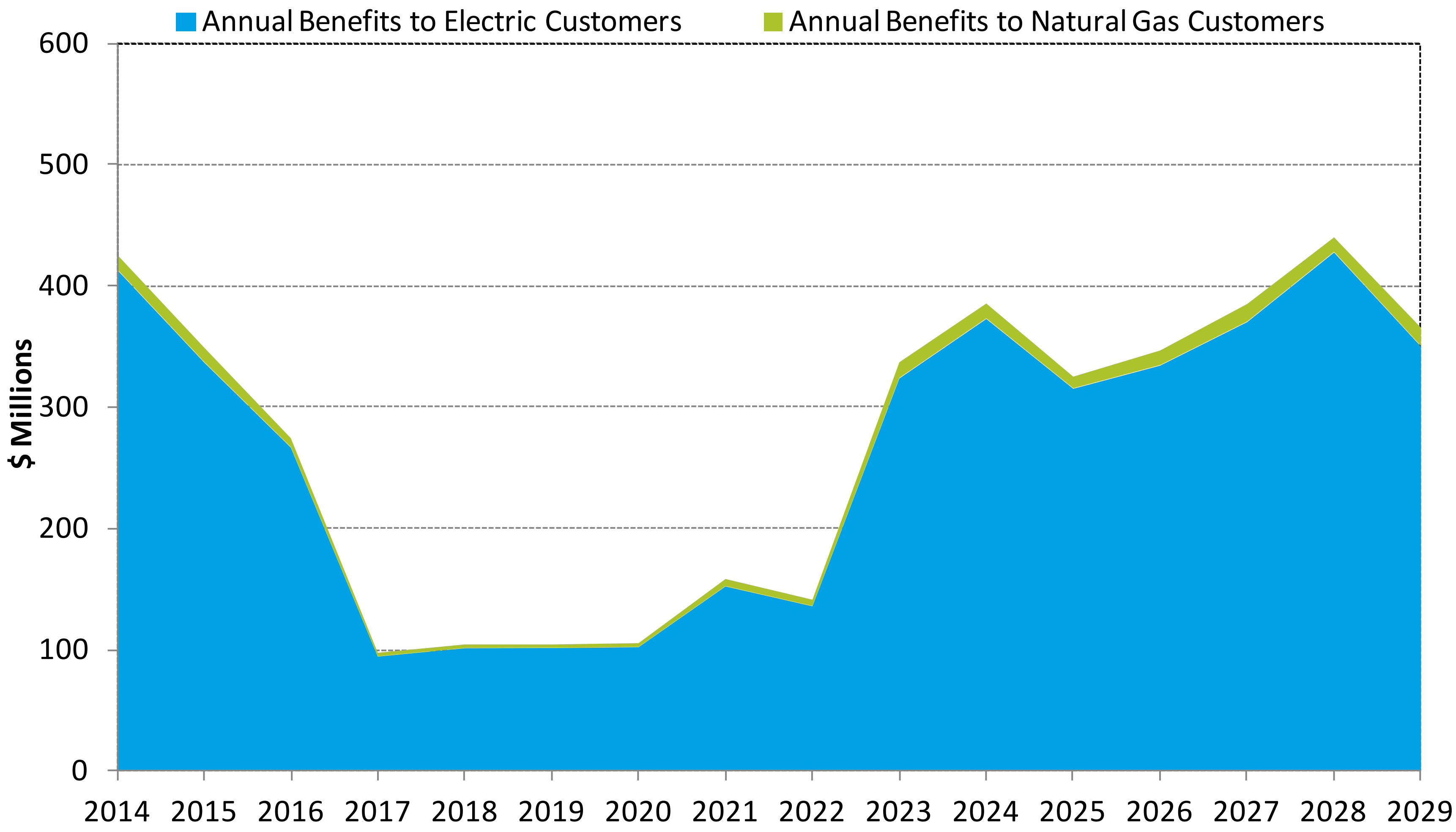
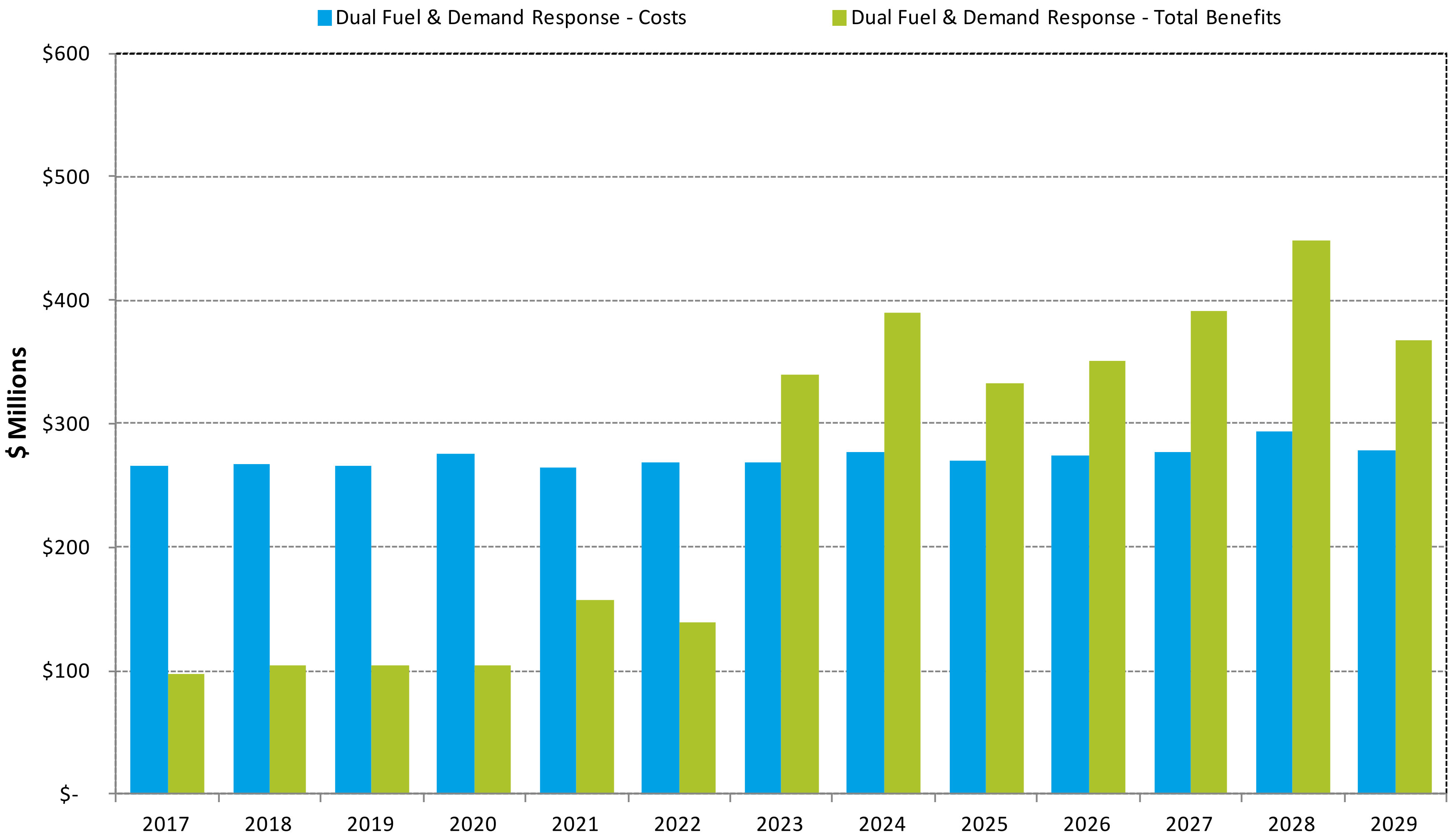
Natural Gas and Energy Customer Benefits with Dual-Fuel Generation and Demand Response



Projected Cost and Benefits of Dual-Fuel and Demand Response



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