



RCA Amendment: Treatment of Storage Outage

Ben Griffiths | Markets Committee | March 2024

About LS Power

LS Power is a development, investment and operating company focused on the North American power and energy infrastructure sector

- Founded in 1990, LS Power has 280 employees across its principal and affiliate offices in New York, New Jersey, Missouri, Texas and California
- LS Power is at the leading edge of the industry's transition to low-carbon energy by commercializing new technologies and developing new markets.
 - **Utility-scale power projects across multiple fuel and technology types**, such as pumped storage hydro, wind, solar and natural gas-fired generation
 - **Battery energy storage**, market-leading utility-scale solutions that complement weather dependent renewables like wind and solar energy
 - **High voltage electric transmission infrastructure**, which is key to increasing grid reliability and efficiency, as well as carrying renewable energy from remote locations to population centers
 - **EVgo, the nation's largest public fast charging platform for electric vehicles** and first platform to be 100% powered by renewable energy
 - **CPower Energy Management**, the largest demand response provider in the country that is dedicated solely to the commercial and industrial sector
- Since inception, LS Power has developed, constructed, managed and acquired competitive power generation and transmission infrastructure, for which **we have raised over \$47 billion in debt and equity financing.**
 - **Developed over 11,000 MW of power generation** (both conventional and renewable) across the United States
 - **Acquired over 34,000 MW of power generation assets** (both conventional and renewable)
 - **Developed over 660 miles of high voltage transmission**, with ~400 miles of additional transmission under development

Utilize deep industry expertise as owner/operator

Position Summary

- ISO's proposal for gas accreditation assumes that gas is uniformly available in the region
- Over the past year, LS has provided a variety of evidence that natural gas is *not* uniformly available in New England
 - Using economic techniques, LS showed that gas availability for power generation declines at cold temperatures on downstream locations and on certain laterals [1]
 - Using physical flow data, LS showed that there is gas which is “stranded” in CT [2]
 - By contrast, the ISO and its consultants have provided asserted, but provided no evidence to substantiate claim that fuel is uniformly available for power generators
- Fuel modeling should be unit specific, just like RCA as a whole
- Observed unit fuel access should be factored into overall accreditation, using something like the “hybrid empiricism + modeling” approach described by Brattle [3]
 - Blending observed performance with MRI-type modeling can capture unit-specific operational nuances and certain system risks

1. https://www.iso-ne.com/static-assets/documents/2023/02/a07e_mc_2023_02_07-09_ls_power_unit_specific_gas_modeling_presentation.pdf

2. https://www.iso-ne.com/static-assets/documents/2023/04/a05b_mc_2023_04_11-13_rca_ls_power_unit_specific_gas_modeling_presentation.pdf

3. https://www.iso-ne.com/static-assets/documents/2022/09/a05e_mc_2022_09_13-14_rca_ma_ago_presentation.pptx at 8.

ISO's current approach fails to capture locational aspects of fuel

- The ISO is currently proposing to use different approaches to model a gas resource in summer and winter
 - **Summer:** Unit-specific MRI values, based on EFORd
 - **Winter:** ISO intends to create a

Prior Work on Gas Availability in New England

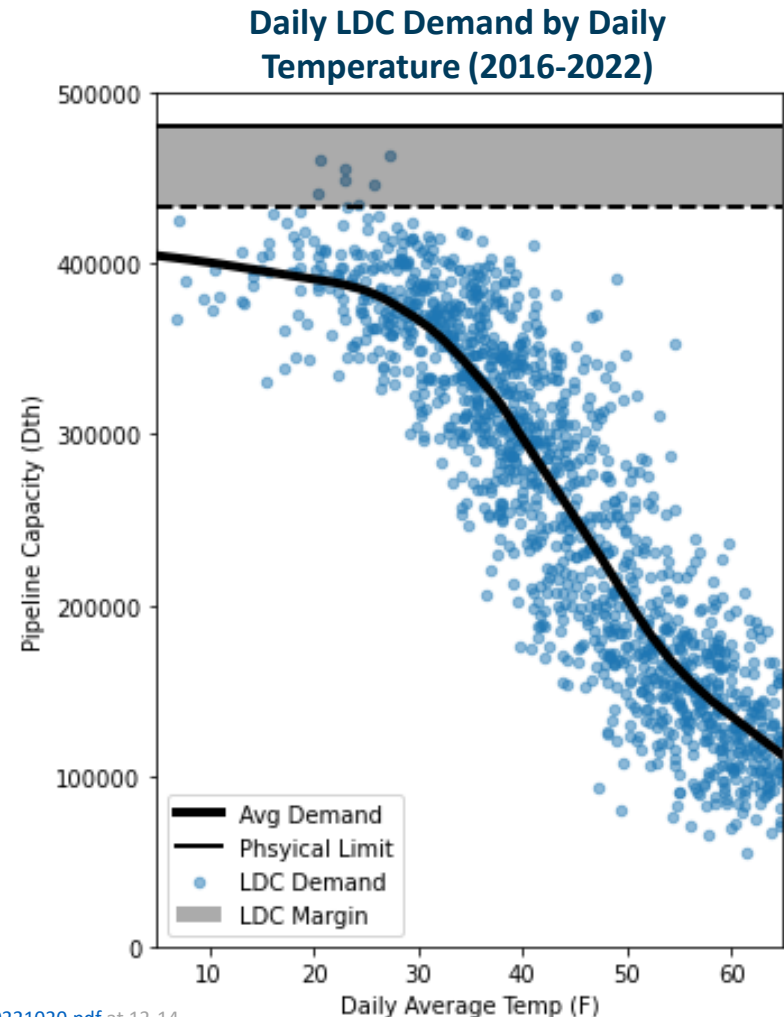
Estimated Temperature-Dependent Derates

- On a region-wide basis, expected unavailability reaches 27% at the coldest temperatures
 - The assessed units have aggregate winter capacity of 9,080 MW so a 27% MW-weighted derate is equivalent to about 6,625 MW of available gas capacity at very cold temperatures
- On state level,
 - **Connecticut** produces energy at a higher level that we would expect across a range of temperatures and there is no appreciable temperature-dependent output deviation
 - This suggests that the gas system is not constrained in Connecticut at any observed temperature
 - Two of the three **Maine** units exhibit significant degradation at cold temps (in excess of 65%) but the third fares better, perhaps due to contracting
 - **MA** is highly variable with several units exhibiting decreasing output as temperatures fall; others show persistent issues across range of colder temps
- On a unit level,
 - Derates range from 0% to 97% at very cold temperatures

	T < 10	10 ≤ T < 20	20 ≤ T < 30	30 ≤ T < 40	40 ≤ T < 50	50 ≤ T
ISO-Wide Results						
Total	-27%	-19%	-16%	-15%	-11%	-1%
State-Wide Results						
MA	-52%	-38%	-27%	-25%	-20%	-1%
ME	-41%	-32%	-29%	-33%	-19%	-1%
RI	-28%	-12%	-9%	0%	-1%	0%
NH	0%	-1%	-18%	-22%	-17%	0%
CT	0%	0%	0%	0%	0%	0%
Facility Specific Results						
[UNIT A]	-97%	-92%	-85%	-62%	-29%	-1%
[UNIT B]	-94%	-95%	-84%	-73%	-51%	0%
[UNIT C]	-89%	-75%	-73%	-49%	-23%	0%
[UNIT D]	-75%	-67%	-62%	-65%	-33%	0%
[UNIT E]	-65%	-46%	-42%	-49%	-32%	-3%
[UNIT F]	-51%	-37%	-44%	-34%	-23%	0%
[UNIT G]	-48%	-47%	-21%	-7%	-8%	-2%
[UNIT H]	-47%	-36%	-27%	0%	0%	-1%
[UNIT I]	-47%	-24%	0%	-9%	-20%	0%
[UNIT J]	-43%	-20%	-10%	-20%	-19%	-2%
[UNIT K]	-24%	-9%	-2%	-9%	-7%	0%
[UNIT L]	-18%	1%	0%	0%	-1%	0%
[UNIT M]	0%	-1%	-18%	-22%	-17%	0%
[UNIT N]	0%	0%	0%	0%	0%	0%
[UNIT O]	0%	0%	0%	0%	0%	0%
[UNIT P]	0	0%	0%	0%	0%	0%
[UNIT Q]	0%	0%	0%	0%	0%	0%
[UNIT R]	0%	0%	0%	0%	0%	-1%
[UNIT S]	0%	-4%	0%	0%	0%	-2%

LDC ownership of firm transmission on the Algonquin G-Lateral limits gas generation on that lateral on cold days

- LDCs own approximately all FT capacity on Algonquin G-Lateral (or, conversely, G-Lateral sized for LDC demand).
- As temperatures decrease, LDC demand approaches lateral capacity, less a reserve margin, leaving little-to-nothing for power gen.
- Gas-only resources on G-lateral should not be expected to have gas available on cold days, even if otherwise in merit.
- On other portions of gas system, marketers own a meaningful amount of capacity, yielding different gas availability dynamics.
- N.b., the EMM has published complementary results for LDCs in New York with same punchline. [1]



1. https://www.potomaceconomics.com/wp-content/uploads/2022/10/MMU-Gas-Availability-Presentation_20221020.pdf at 12-14.

Integrating Unit Specific Fuel into Accreditation

Prior work on Fuel Availability in New England

Premise: gas constraints can be inferred in power market data

- In practice, we know that (at least) parts of the gas system are *physically constrained* at cold temperatures. It is generally agreed that the system is *unconstrained* at warmer temperatures.
 - If winter was unconstrained, region wouldn't be subject to dramatically higher gas prices in winter season
- Is there a way to compare how individual units would operate if the gas system were physically unconstrained in both summer *and* winter?
- If so, we can attribute to fuel limitations the difference in performance between (a) **observed** real-world gas gens and (b) these same units in an **estimated** unconstrained counterfactual.
 - If this comparison finds no difference in performance, then fuel constraints are “non-binding”
 - If this comparison finds common reductions in output across all units, then a uniform derate might be reasonable.
- Analogous to studying how “relaxing” transmission interface limits affects unit dispatch.
 - ISO has run various Economic Studies evaluating the ability of transmission upgrades to increase production from constrained renewables in Maine [1]
 - In this analysis, we rely on the same concept but invert the process. Instead of changing interface constraints to observe prices and generation quantity, here we change prices to observe changes in generation and, implicitly, the constraints themselves

1. E.g. the 2019 Economic Study evaluating the effectiveness of transmission upgrades to Orrington South to increase production from constrained onshore renewables in Maine. <https://www.iso-ne.com/static-assets/documents/2020/10/2019-renew-es-report-final.docx> . See also: https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_keene_road_increased_export_limits_fina.docx

Solution: gas constraints are inferred through power market data

- New analysis quantifies gas availability on a regional-, state-, and unit-specific basis
- Analysis infers the presence and magnitude of gas-supply constraints by comparing **expected** generation for gas-only electric generators in the ISO-NE with **observed** generation from these same resources
- **Observed generation** based on public data from EPA CEMS database
- **Expected generation** based on optimization model relying on imputed economic offers
 - Expected generation assumes that gas system is *unconstrained* for purposes of offer formulation (i.e. resources can buy timely gas at the Citygate price, plus a fixed “summer” basis)
- Economic approach controls for fuel costs and unit operational characteristics
 - There may be periods with oil-gas price inversion where gas is available but not used due to price
 - Higher heat-rate plants will tend to run less often than lower heat-rate plants
 - Focus on *output* rather than *availability* avoids concerns about “unknown” unavailability
- After controlling for economics, analysis attributes “missing” cold-weather production to fuel unavailability
 - May **overstate** total impact of fuel unavailability if a unit is on a non-fuel forced outage

Comparing Observed and Expected Generation

- With observed and expected generator output developed, it is possible to compare how we *expect* resources to perform versus how they actually did.
 - The deviation between expected and observed generation reflects the impact of fuel-access limitations
- Derate can be computed across a whole winter season but can also be computed in specific temperature ranges

$$Derate_{Gen | Temp \leq Threshold} = \frac{\sum Obseved\ Gen\ with\ Temps \leq Threshold}{\sum Expected\ Gen\ with\ Temps \leq Threshold} - 1$$

which is equivalent to the fraction of hours, in a given temperature range, that a resource was observed running divided by the number of hours it was expected to run, less one.

- This derate metric can be considered a metric of locational fuel (un)availability because it is estimating the proportion of time a resource can actually generate electricity at a given temperature due to fuel constraints
 - Because a unit cannot have a “negative” derate, we bound the metric to a range from -100% to 0%
- A negative value indicates that a resource is producing *less* energy than we would expect while a positive value indicates that a resource is producing *more* energy than we would expect.
 - If a resource was observed to run for 100 hours at temperatures below 10 degrees, but expected to run for 400 hours, then the resulting deviation of -75% suggests that the resource either cannot obtain fuel, or can only obtain very high cost fuels

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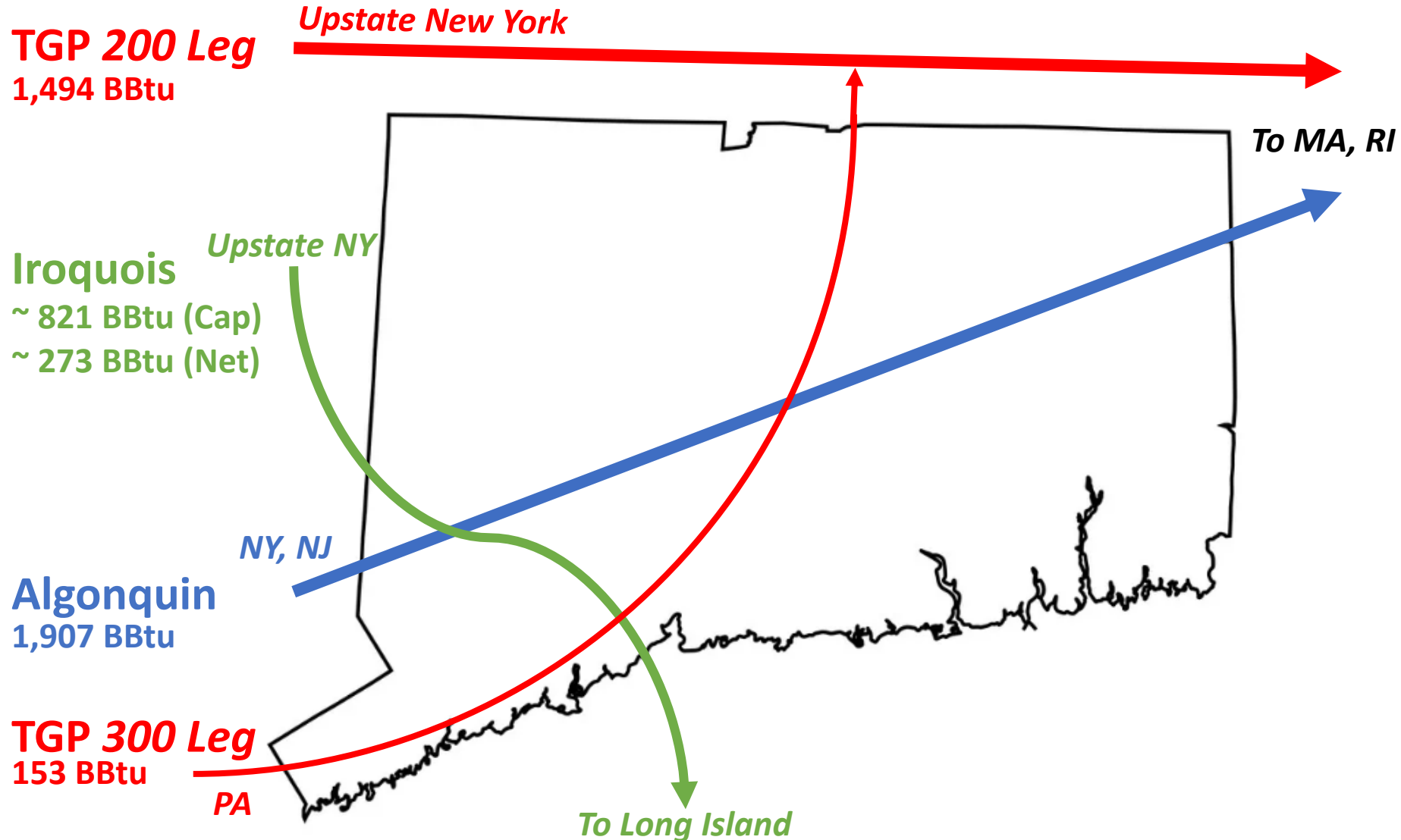
Pipeline Entitlements, Observed Flows, & Residual Gas

Materials Reproduced from LS Power's April 2023 MC Presentation

Estimating Gas Flows & Gas Available for Power Generation

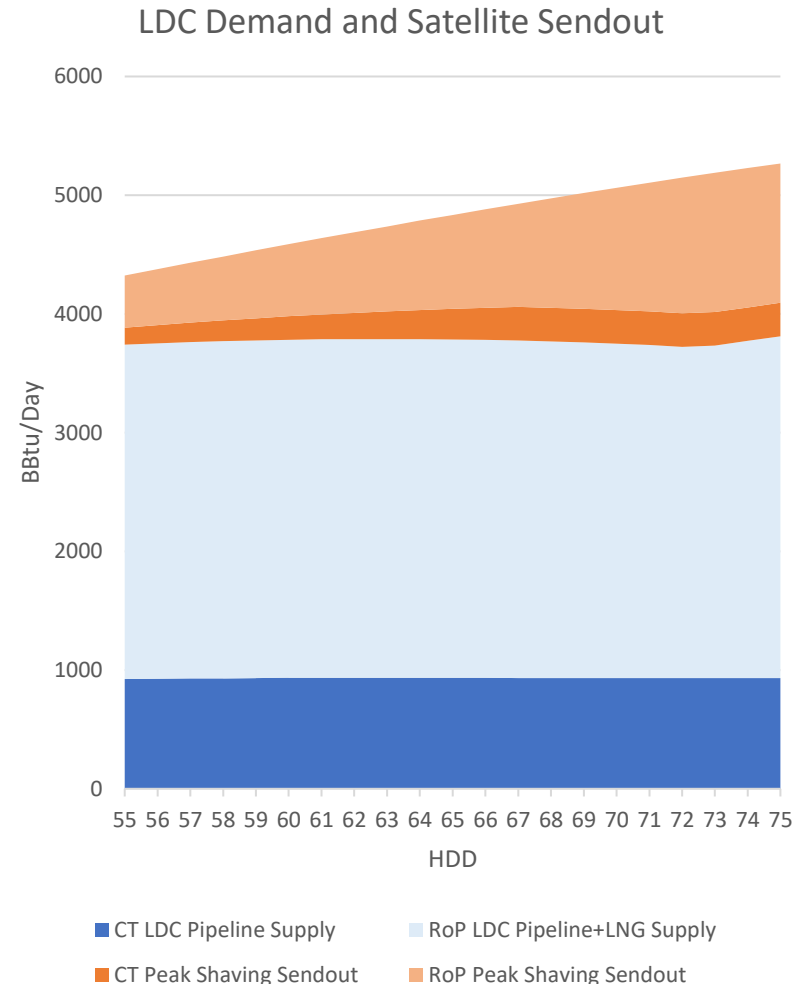
- This module estimates the supply of pipeline gas available for power generation in Connecticut using two methods
 - Review of firm transport entitlements on the interstate pipelines
 - Observed flows into Connecticut, as a function of temperature
- Analysis tracks pipeline gas flows into and out of Connecticut, incremental supply from LDC satellite LNG facilities, and domestic consumption from LDCs on a daily basis
 - Pipeline gas flows based on daily nominations sourced from pipeline informational postings
 - LDC demand and satellite send-out sourced from ISO-NE / ICF modeling
- As discussed within, we find that even on the coldest of days there is **239 to 453 BBtu/d of gas for power generation in the state**
 - On days with OFOs, gas resources outside of Connecticut would not be able to tap into this quantity, leaving it effectively “stranded” for sole use by generators *within* Connecticut
- While probably not enough to cover 24x7 operation at all gas units, it provides a significant advantage to resources located in the state
 - Based on physical estimates, units in CT may warrant DQC derates around 14%, compared with a regional derate of 52.25%. Reasonable estimates suggest the CT derate should not exceed 29%

Review: Pipelines in Connecticut



LDC Demand for Pipeline Gas in Connecticut

- ICF's LDC demand and satellite sendout models are regional in scope, not zonal, so LS needed to estimate CT specific values to assess availability in the state
- CT's LDCs expect their "worst-case" design day gas demand occurs at warmer temperatures than LDCs located elsewhere in the region (~70 EDDs vs ~80 EDD)
- During design day conditions, ICF reports that CT LDC's expect to require **1,216 BBtu of gas [1]**.
 - This is about 25% of regional demand at 67 HDD.
 - We assume CT constitutes ¼ of demand at warmer temps
- CT LDC's own **284 BBtu/d of send out capacity at satellite LNG facilities** for use in design-day conditions,
 - This is about 20% of the region's 1,317 BBtu/d but about 25% of expected sendout at CT's design day temps
- Subtracting satellite sendout from LDC demand, we estimate that maximum **LDC demand on the pipelines equals 933 BBtu/d**



1. ICF, March MC, Slide 12

Review of pipeline firm transport entitlements confirms presence of “residual” gas in Connecticut

- During the most stressed days (i.e., those with OFOs), pipelines will operate such that FT entitlements can be respected
 - So, a conservative estimate the magnitude of pipeline gas deliverable to Connecticut assumes that pipeline will deliver gas to Connecticut commensurate with entitlements, but no more
 - Should not assume that a pipeline operator would run pipe above rated output of line for sustained periods
- Using data from the pipeline informational filings, we conducted a detailed review of all contracted capacity on the three interstate pipelines *into* Connecticut on contracts originating *outside* of New England
 - This review *only includes* entitlements to physical delivery points (excludes throughput meters, intra- and interstate interconnects) so there is no double-counting of gas that might be transferred between pipelines or gas transported into the state using multiple contracts (Point A->B and B->C)
 - We differentiate between gas sourced from *outside* the region (e.g. NY, NJ or points further west) and backhaul capacity from MA that might enable LNG flows or transferring gas from the TGP mainline to Algonquin at Mendon
- Results indicate that there is 1,222 to 1,386 BBtu of FT entitlements into Connecticut

FT Entitlements into Connecticut, Dth, Based on Contracts as of 1/1/2023

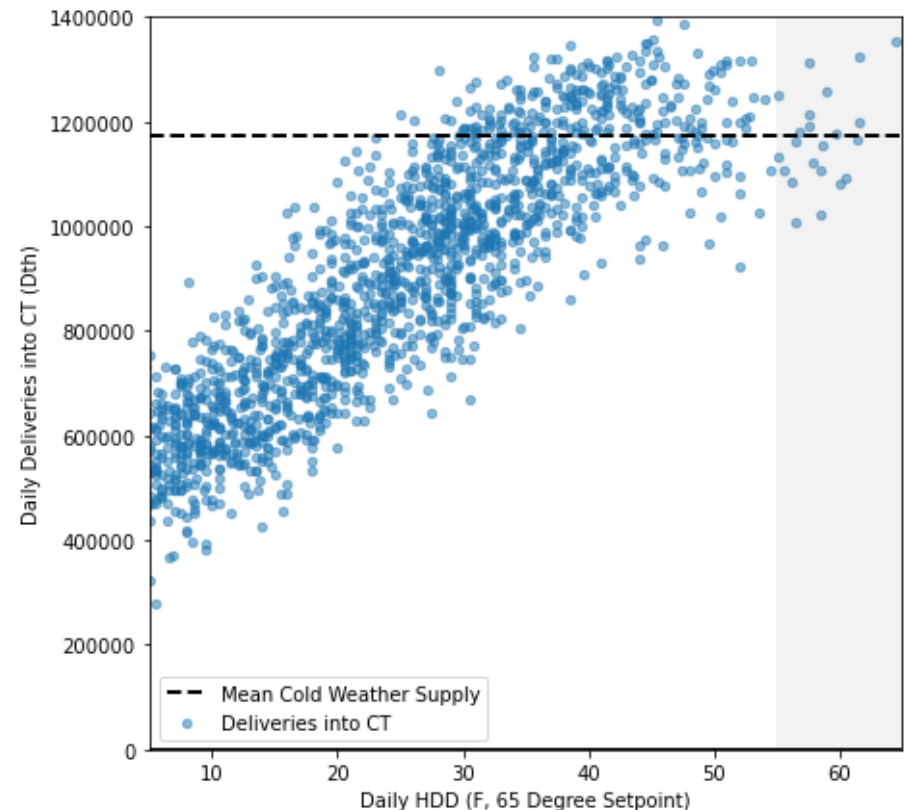
Pipeline	From outside NE	Backhaul from MA	Total into CT
Algonquin	515,270	124,113	639,383
Iroquois	245,724	0	245,724
TGP	461,392	40,000	501,392
Total	1,222,386	164,113	1,386,499

Review of historical pipeline flows confirms presence of “residual” gas in Connecticut

- Contracted flows (prior slide) may differ from observed flows so the next approach looks at observed flows into Connecticut on cold days to confirm alignment between both approaches
- Analysis tracks pipeline gas flows into and out of Connecticut on a daily basis using daily nominations sourced from pipeline informational postings, including Genscape’s estimate of no-notice flows
 - Study period runs Dec-2014 through Feb-2022 and includes a number of cold days
 - Temperature data, computed as daily HDDs, based on weather at Bradley Field, CT
- Analysis accounts for flows *between* different pipelines (e.g. from Algonquin to Iroquois) as well as flows wheeled through Connecticut to points outside the region (e.g. from CT to Long Island on Iroquois)
- While observed flows are more variable than entitlements, we find that on cold days (where HDD > 55), flows into Connecticut average 1,172 BBtu.
 - Observed flows on cold days are 4% lower, on average, than forward haul FT entitlements. This suggests that actual gas deliveries to Connecticut are a little lower than the contractual maximum but that there may be additional unused back-haul capacity that could be used if needed
 - Also suggests that generators in Connecticut are using the “residual” gas that is available in Connecticut that cannot be transported further downstream due to lack of entitlements
- **Observed flows align with entitlement data: residual gas is in Connecticut and power generators make use of it**

Total Supply into Connecticut on Cold Days: ~1,200 BBtu

- Adding Algonquin, TGP, Iroquois flows together can compute net inflows into CT.
 - Gas demand increases as temps get colder
- Looking just at days where HDD ≥ 55 , gas deliveries to Connecticut average 1,172 BBtu
 - Mean: 1,172 BBtu
 - Always exceed 1,000 BBtu
 - Exceeds 1,081 BBtu on 90% of days
 - Exceeds 1,165 BBtu on 50% of days
 - Exceeds 1,350 BBtu on 10% of days
- This assessment is **conservative** (i.e., low) because it only tracks the flows that have historically occurred, it does not account for possibility that:
 - pipelines ran at less than 100% throughput
 - LNG delivered to CT, additional satellite sendout, or offsetting gas demand outside of CT
 - Backflows into CT from MA on Algonquin



Residual Gas for Power Generation

Connecticut has enough residual gas from FT entitlements to allow gas-only generators there to run at 1.5-3x of their pro-rata “share” of generation during cold conditions

■ Pulling Connecticut supply and demand together....

- Aggregate pipeline supply: 1,172 to 1,386 Bbtu/d
 - 1,172 Bbtu/d: Observed Flows in Cold Weather (average)
 - 1,222 Bbtu/d: Forward Haul Entitlements into CT
 - 1,386 Bbtu/d: Forward + Back Haul Entitlements into CT
- LDC pipeline demand: 933 Bbtu/d

■ As LDC design day demand is ~933 Bbtu, and there is 1,172 Bbtu to 1,386 Bbtu of supply into Connecticut, **then there is 239 to 453 Bbtu/d left over for power generation**

- Recall, Levitan’s proposed Firm Daily Operational Requirement (FDOR) for the *region* averages ~3,200 MW/hr
 - This works out to 76.8 GWh/d and requires 614.4 Bbtu of gas (assuming fleet heatrate of 8 MMBtu/MWh)
 - Suggests gas fleet needs average capacity factor of 39%, excluding peakers and operationally limited resources, to hit the target 3,200 MW
- Units in CT represent 32% of regional gas-only capacity (~2.6 GW) but can support 45% to 84% of FDOR. Put plainly, **units in Connecticut can and do support an outsized share of generation on cold days**
 - Based on forward haul entitlements, we would expect CT units to be able to produce 53% of FDOR energy
 - Review of CEMS data shows that on the 23 days where HDDs exceed 55, units in Connecticut are actually producing 52-62% of region’s gas-only generation (depending on which units are included in sample and averaging approach) – at least as much as we would expect from the pipeline entitlements

Questions?