October 8, 2024

EVERSOURCE

PSNH Rate Case, Pre-Hearing Technical Conferences

Follow-up requests from October 2 and 3rd, 2024

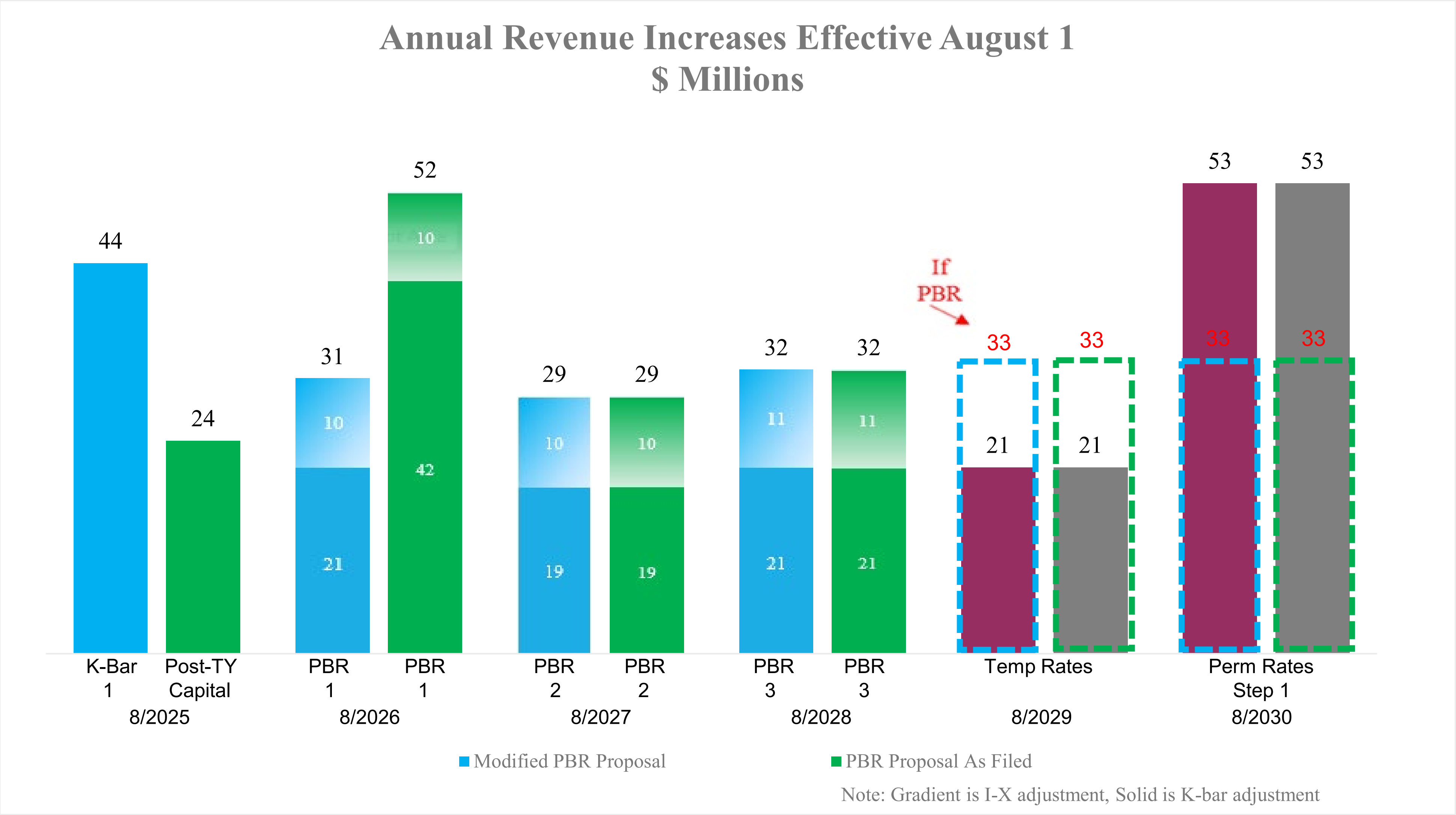
Technical Session Requests

1. Timeline for 2024 Capital Project Documentation
2. Breakdown of PBR/K-Bar Adjustments
3. Exogenous Factors
4. Current Reconciling Mechanisms
5. Budget by Investment Category
6. Core Capital Definition
7. Comparison of PBR Plans by component

Request #1: Timeline for 2024 Project Documentation

- The Company can provide capital project documents for the first 3 quarters of 2024 by late January.
- The Company can provide the remaining documentation for the last quarter of 2024 in late March.
- The 2024 capital addition documentation can be reviewed in a parallel review process, with a procedural schedule that provides discovery and hearings on a different track than the rest of the rate case, with rates effective on August 1, 2025. This process is similar to the process used in DE 19-057.
- The Company has described an alternative proposal in response to PUC 1-003 if the PBR plan is adopted.

Request #2: Breakdown of PBR incl. K-Bar



Request #2: Breakdown of PBR incl. K-Bar (cont.)

Rate Impacts PBR incl. K-bar vs. Step Adjustments

Figure OCA 1-068(a):
Annual Revenue Increases
PBR vs. Step Adjustments

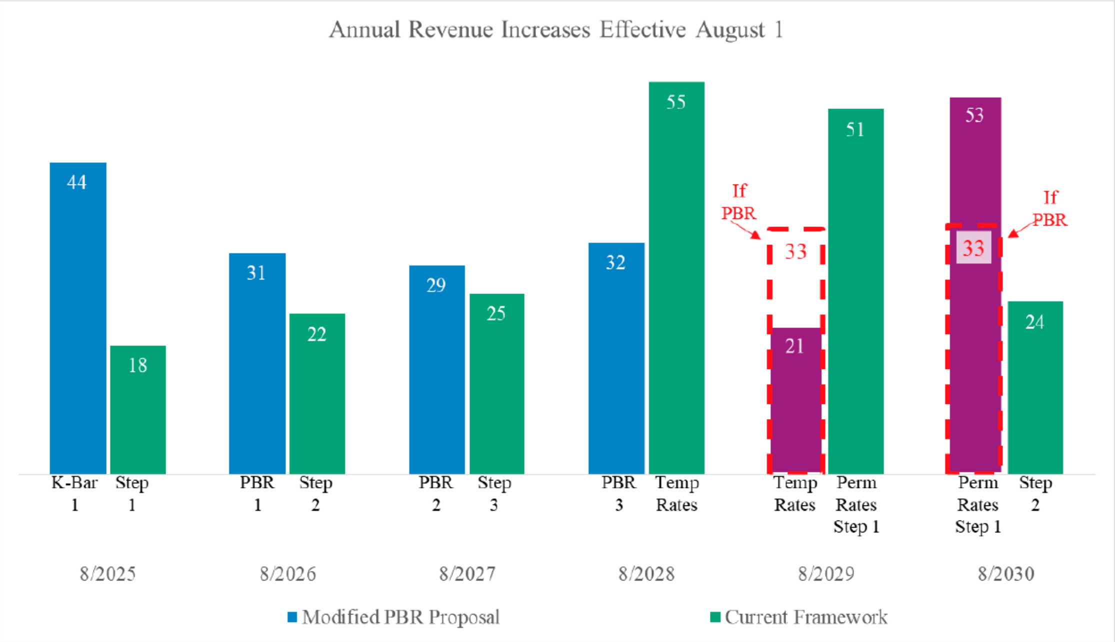


Table OCA 1-068(a):
Estimated Bill Impacts – PBR, Rate Case in 2029

	KBAR #1 Rate Change 8/2025	PBR #1 Rate Change 8/2026	PBR #2 Rate Change 8/2027	PBR #3 Rate Change 8/2028	Rate Case (Temp) Rate Change 8/2029	Rate Case (Perm) Rate Change 8/2030	Cumulative Rate Change
Revenue Requirement Change ($M)	$44	$31	$29	$32	$21	$53	$210
Distribution Rate Increase	7.33%	4.81%	4.30%	4.54%	2.85%	7.00%	34.99%
Total Bill Increase							
Residential (R)	3.30%	2.25%	2.06%	2.23%	1.43%	3.56%	15.77%
General Service (G)	2.81%	1.93%	1.77%	1.92%	1.23%	3.08%	13.42%
Primary General Service (GV)	1.37%	0.95%	0.88%	0.97%	0.63%	1.58%	6.55%
Large General Service (LG)	1.11%	0.77%	0.72%	0.78%	0.51%	1.28%	5.28%
Street Lighting	5.38%	3.60%	3.25%	3.47%	2.20%	5.44%	25.70%
Company-wide PSNH	2.58%	1.77%	1.63%	1.77%	1.14%	2.85%	12.32%

Table OCA 1-068(b):
Estimated Bill Impacts
Step Adjustments, Rate Case in 2028

	Step #1 Rate Change 8/2025	Step #2 Rate Change 8/2026	Step #3 Rate Change 8/2027	Rate Case (Temp) Rate Change 8/2028	Rate Case (Perm) / Step #1 Rate Change 8/2029	Step #2 Rate Change 8/2030	Cumulative Rate Change
Revenue Requirement Change ($M)	$18	$22	$25	$55	$51	$24	$195
Distribution Rate Increase	3.00%	3.56%	3.90%	8.27%	7.08%	3.11%	32.49%
Total Bill Increase							
Residential (R)	1.35%	1.63%	1.82%	3.94%	3.51%	1.60%	14.64%
General Service (G)	1.15%	1.39%	1.56%	3.37%	3.03%	1.38%	12.46%
Primary General Service (GV)	0.56%	0.68%	0.77%	1.68%	1.53%	0.71%	6.08%
Large General Service (LG)	0.45%	0.55%	0.62%	1.36%	1.25%	0.58%	4.91%
Street Lighting	2.20%	2.63%	2.92%	6.23%	5.44%	2.43%	23.86%
Company-wide PSNH	1.06%	1.28%	1.43%	3.11%	2.79%	1.28%	11.44%

Request #2: Breakdown of PBR incl. K-Bar (cont.)

Rate Impacts for 1st Generation and 2nd Generation PBR in MA

NSTAR Electric Company
Impact of Performance-Based Rate Plans in Massachusetts
2018 - 2032

	Actual						
Summary	**1/1/2018**	**1/1/2019**	**1/1/2020**	**1/1/2021**	**1/1/2022**	**1/1/2023**	**1/1/2024**
Percent Change in Distribution Revenues (%)		3.10%	3.17%	2.74%	3.28%	5.88%	9.06%
Annual Change in Distribution Revenues ($)	37,116,674	$ 31,857,378	$ 33,616,226	$ 29,937,587	$ 36,846,769	$ 64,255,303	$ 104,909,116
Residential Bill Impact		0.8%	0.9%	0.8%	0.9%	3.8%	2.1%

	Forecast							
Summary	**1/1/2025**	**1/1/2026**	**1/1/2027**	**1/1/2028**	**1/1/2029**	**1/1/2030**	**1/1/2031**	**1/1/2032**
Percent Change in Distribution Revenues (%)	4.68%	4.99%	5.43%	5.36%	5.00%	4.78%	4.54%	4.26%
Annual Change in Distribution Revenues ($)	$ 59,060,645	$ 65,909,934	$ 75,305,565	$ 78,442,528	$ 76,992,448	$ 77,423,671	$ 76,979,894	$ 75,576,075
Residential Bill Impact	1.1%	1.2%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%

Request #3: Exogenous Factors

Company/Element	Exogenous Z Factor	Exogenous Cost Threshold	Operating Revenues	Number of Customers
PSNH Proposed **(DE 24-070)**	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = $1.5M	$1.5m	$1.5b	539k
National Grid **(D.P.U. 23-150)**	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $3.6m adjusted by GDP-PI annually	$3.6m	$2.8b	1.3m
Unitil Electric PBR1 **(D.P.U. 23-80)**	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $110,000 adjusted by GDP-PI annually	$110k	$88m	46k
NSTAR PBR2 **(D.P.U. 22-22)**	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $4M adjusted by GDP-PI annually	$4m	$3.1b	1.4m
NSTAR GAS PBR1 **(D.P.U. 19-120)**	Positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $700,000 adjusted by GDP-PI annually	$700k	$500m	296k
NSTAR PBR1 **(D.P.U. 17-05)**	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = $5M adjusted by GDP-PI annually	$5m	$3.2b	1.4m

Request #4: Proposal for Reconciling Mechanisms

Regulatory Reconciliation Adjustment Mechanism (RRA)			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Regulatory Assessments and Consultant Costs	Regulatory Commission annual assessments and consultants hired or retained by the Commission and OCA.	1) Regulatory assessments for the most recent FY 2) Consultant costs incurred during the test year	Eliminate annual reconciliation of over/under through RRA; Annual amount to be recovered through base rates, subject to reconciliation at the Company's next rate case.
Property Tax	Property tax expenses, as compared to the amount in base rates (DE 19-057)	2024 Tax Year property expense	Eliminate annual reconciliation of amount over/under base rates
Vegetation Management	Vegetation management program variances as compared to the amount in base rates (DE 19-057)	2023 actual plus post-TY adjustment for $2m budget increase	Eliminate annual reconciliation of amount over/under base rates
Storm Cost LTD True-Up	Storm cost amortization final reconciliation and annual reconciliation updated for actual cost of long-term debt	Proposed LTD cost in proceeding	Eliminate annual reconciliation of amount over/under base rates
Lost Base Revenues - Net Metering	Lost-base distribution revenues associated with net metering, as calculated consistent with RSA 362-A:9, VII and the Commission's approved method in Order No. 26,029 (June 23, 2017) in Docket No. DE 16-576.	Not Included	Eliminate annual recovery for expenses incurred after August 1, 2024
Rate Case Expense	Order No. 26,634 (May, 27, 2022) at 1. The Commission approved a settlement agreement relating to Eversource's motion to recover rate case expenses for DE 19-057. Pursuant to that agreement, Eversource is authorzied to collect $1,762,807 through its Regulatory Reconciliation Adjustment mechanism over five years, beginning August 1, 2022.	1) Recover remaining balance of approved rate case expense from DE 19-057 over 5 years 2) DE 24-070 rate case expense over 5 years	Eliminate annual reconciliation of over/under through RRA, subject to reconciliation at the Company's next rate case.

Request #4: Proposal for Reconciling Mechanisms (cont.)

Pole Plant Adjustment Mechanism			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Pole Replacement O&M Transfer costs	The actual costs associated with replacement poles for the prior calendar year based on the actual number of poles replaced and the actual Eversource cost to transfer the conductor from the old to the new poles.	Actual expenses for 2023 Test Year	Eliminate annual recovery for expenses incurred after August 1, 2024
Annual Inspection Costs	The actual inspection costs and other upfront costs for the prior calendar year consisting of the number of poles inspected in the former Consolidated maintenance area and the per pole rate in effect. Upfront costs of $250,000 in years 1 and 2 and $75,000 in year 3 will also be included.	Actual expenses for 2023 Test Year	Eliminate annual recovery for expenses incurred after August 1, 2024
Pole Attachment Revenue	Incremental third-party pole attachment revenues is applied as an offset to the items in (a) and (b). Pole attachment revenues for formerly Consolidated owned poles will be tracked separately and billed at the Consolidated rate at the time of closinguntil a full pole attachment survey is conducted and, or a single, unified rate is applied to all poles.	Not Included - amount not known and measurable at this time	Eliminate annual recovery for expenses incurred after August 1, 2024
Vegetation Management Expense	The incremental vegetation management expense is calculated as the vegetation management expenses formerly billed to Consolidated.	Normalized actual expenses for 2023 Test Year by reflecting a monthly average of CCI vegetation management billings from November 2017 through December 2023 annualized to reflect a twelve-month period. This resulted in a decrease to the actual test year vegetation management expense of $902,206.	Eliminate annual recovery for expenses incurred after August 1, 2024

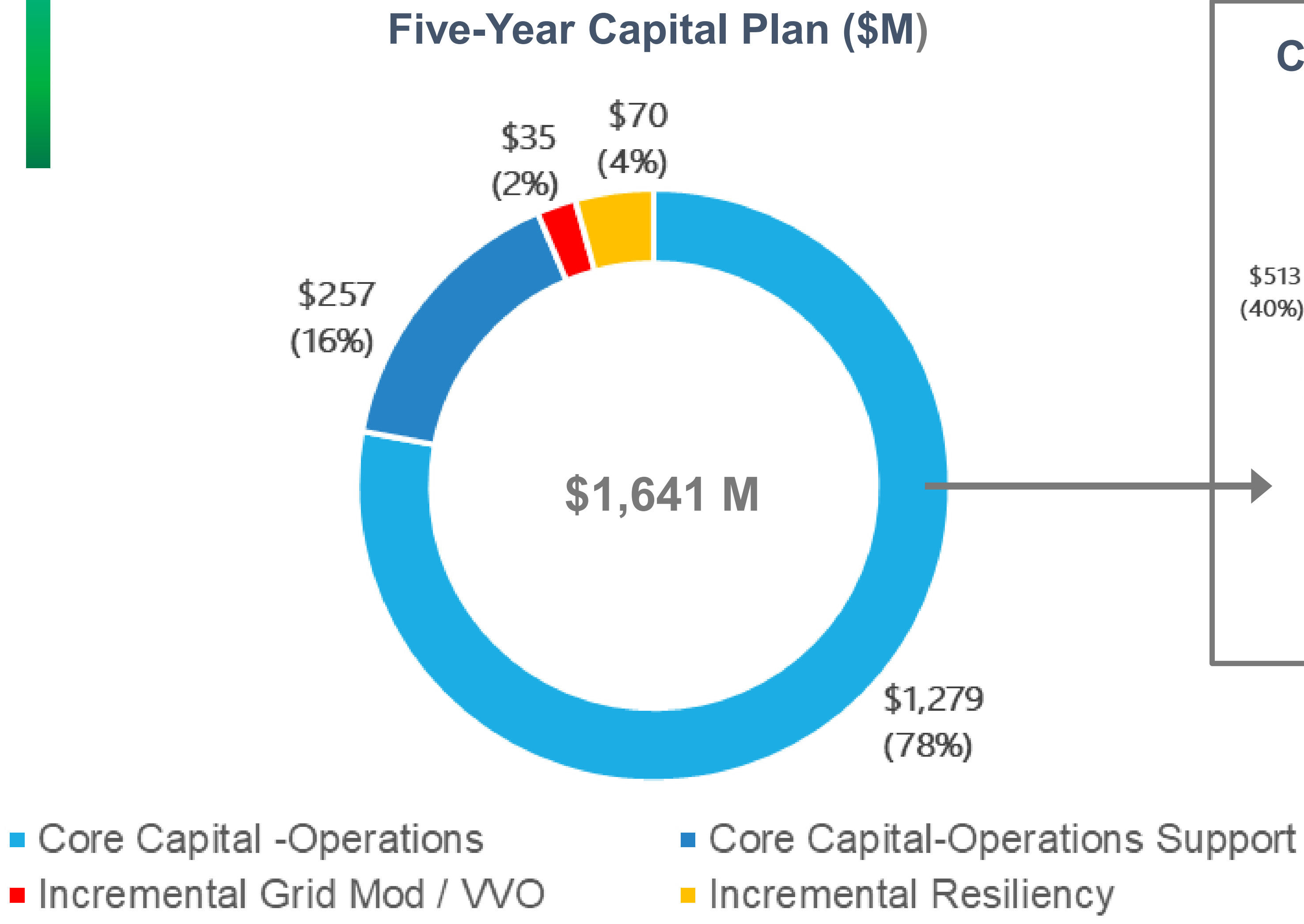
Request #4: Proposal for Reconciling Mechanisms (cont.)

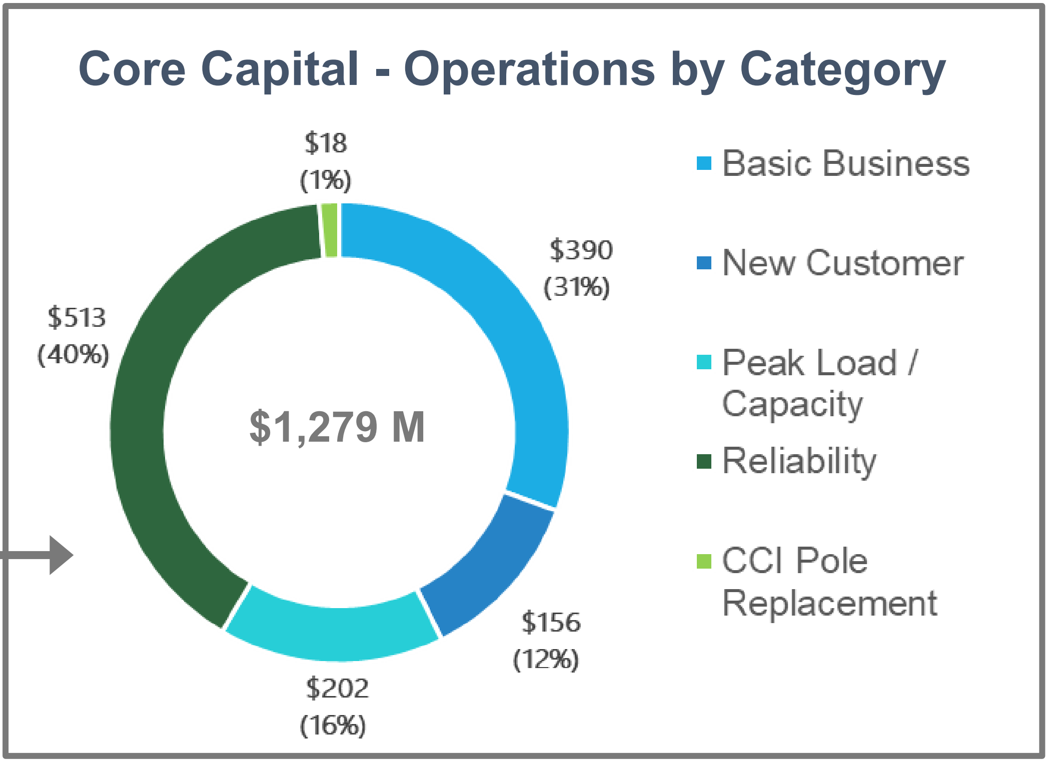
Other			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Lost Base Revenues - Energy Efficiency	Systems Benefits Charge	Not Included	Eliminate annual recovery for expenses incurred after August 1, 2024

Request #4: Proposal for Reconciling Mechanisms (cont.)

Other Mechanisms (No Changes)			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Systems Benefit Charge	To fund energy efficiency and energy assistance programs	No costs included in DE 24-070	No change except for the elimination of energy efficiency-related lost base revenues as shown in previous slide.
Stranded Cost Recovery Charge (SCRC)	The SCRC is the portion of the unbundled retail delivery service bill that is a non-bypassable charge as provided by RSA 369-B:4,IV and RSA 374-F:3, XII to recover the portion of the Company's Part 1 and Part 2 Stranded Costs that are allowed by the Settlement Agreement. The SCRC include the RRB Charge defined in RSA Chapter 369-B, overmarket or under-market IPP and Power Purchase Agreement costs, Non-Securitized Stranded Costs, and other costs and expenses allowed or as authorized by the Commission. The SCRC also includes the: - Regional Greenhouse Gas Initiative ("RGGI") refund as required by RSA 125-O:23,II and Order No. 25,664 dated May 9, 2014, which directs the Company to refund RGGI auction revenue it receives to its Customers through the SCRC. - Costs of implementing 2018 N.H. Laws, Chapter 340, "AN ACT requiring the public utilities commission to revise its order affecting the Burgess BioPower plant in Berlin, … " per Order No. 26,332 ("Ch. 340" costs). - Costs of implementing Section 7.1 of the DE 19-057 Settlement Agreement as approved in Order No. 26,433 to recover Environmental Remediation costs. - Costs of the DE 20-136 Settlement Agreement to recover Net Metering and Group Host costs.	No costs included in DE 24-070	No change
Transmission Cost Adjustment Mechanism (TCAM)	The Transmission Cost Adjustment Mechanism ("TCAM") recovers, on a fully reconciling basis, the costs incurred by the Company for transmission related services. These costs include charges under the ISO-NE Tariff; charges billed to the Company by Other Transmission Providers; third party charges billed to the Company for transmission related services such as charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges; and transmissionbased assessments or fees billed by or through regulatory agencies, including those associated with the ISO-NE, regional transmission organization ("RTO") and the FERC.	No costs included in DE 24-070	No change

Request #5-6: 2025-2029 Capital Investments Core Capital vs. Incremental





- **Core Investments** – Capital projects carried out for Electric Operations consistent with PSNH's long-range plan; funded through base rates, with incremental year-to-year investments after the rate case through a capital mechanism.
- **Resiliency and Grid Modernization:** Proposed capital projects to harden the distribution system against climate change threats; improve control room technology; optimize the system through voltage management; and provide addition planning tools for future forecasting.

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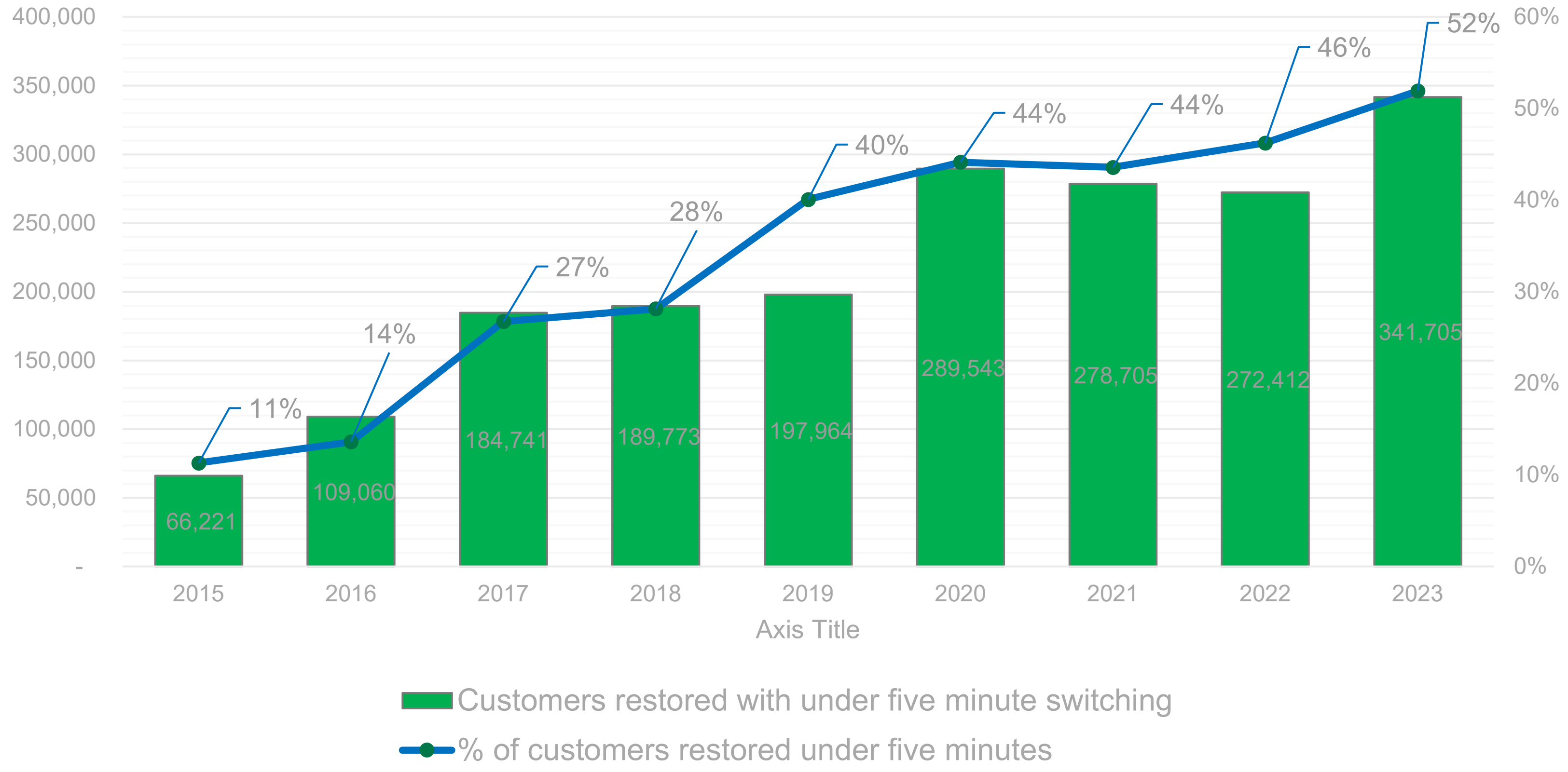
See Bates Page 02172

Request #5-6: Capital Investments Contributing to Distribution Automation Results

Customer impact - under 5 minute restored / % of total under five minute restored



- **Invested more than $765 million** in NH electric distribution system **over the past five years with over $269M invested to restore customers quicker** resulting in 52% of customers impacted restored under 5 minutes through remote switching and power rerouting.

- The **last rate review was in 2019**, and since then, **customers have seen greater reliability** as a result of consistent system investments and automation.

Request #7: Comparison of PBR Plan Components

Company/Element	I Factor	X Factor	Consumer Dividend	Exogenous Z Factor	K Factor	ESM	Term/Stay Out
PSNH Proposed	GDP-PI	Zero	0.15 % when inflation exceeds 2 %	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = $1.5M	K-Bar with rolling three year average base K-Bar amount adjusted to current dollars and capped at 10 % above the company's capital forecast for that year. Major co-optimization projects recoverable when they exceed the 10% K-Factor cap	Asymmetrical ESM with 25 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company. with no sharing of loses	4 year stay out and 4 year PBR term with an option for an additional 4 year stay out
NSTAR PBR1 **(D.P.U. 17-05)**	GDP-PI	-1.56%	0.25 % when inflation exceeds 2 %	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $5M adjusted by GDP-PI annually	No K-Factor but mandated grid modernization program (GMP) investments recoverable outside the price cap.	Asymmetrical ESM with 200 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company and no sharing of losses	5 years

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Note: All of the sample PBR Plans set going in rates based on historical test years adjusted for known and measurable changes. None of the plans include a growth factor, a Y factor, or a re-opener provision.

Request #7: Comparison of PBR Plan Components

Company/Element	I Factor	X Factor	Consumer Dividend	Exogenous Z Factor	K Factor	ESM	Term/Stay Out
NSTAR GAS PBR1 **(D.P.U. 19-120)**	GDP-PI	-1.18 %	0.15 %	Positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $700,000 adjusted by GDP-PI annually	No K Factor	Asymmetric deadband of 100 BP above & 150 BP below authorized ROE. Gains shared 75 % ratepayers / 25 % company. Losses up to 200 BP shared 50/50 Losses over 200 BP shared 75 % ratepayers / 25 % company.	10 years
NSTAR PBR2 **(D.P.U. 22-22)**	GDP-PI	Zero	0.25 % when inflation exceeds 2 %	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $4M adjusted by GDP-PI annually	K-Bar with rolling five year average base K-Bar amount adjusted to current dollars and capped at 10% above the company's capital forecast for that year.	Asymmetrical ESM with 200 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company and no sharing of losses	5 years with an option for an additional 5 years

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Request #7: Comparison of PBR Plan Components

Company/Element	I Factor	X Factor	Consumer Dividend	Exogenous Z Factor	K Factor	ESM	Term/Stay Out
Unitil Electric PBR1 **(D.P.U. 23-80)**	GDP-PI	Zero	0.25 % when inflation exceeds 2 %	Includes but not limited to positive or negative cost changes from (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. Threshold = 0.001253 times total operating revenues = $110,000 adjusted by GDP-PI annually	K-Bar with rolling five year average base K-Bar amount adjusted to current dollars and capped at 10% above the company's capital forecast for that year.	Asymmetrical ESM with 100 BP deadband above authorized ROE. Gains shared 75 % ratepayers / 25 % company and no sharing of losses	5 years

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PSNH Rate Case, Pre-Hearing Technical Conference

October 8, 2024

DSP Overview

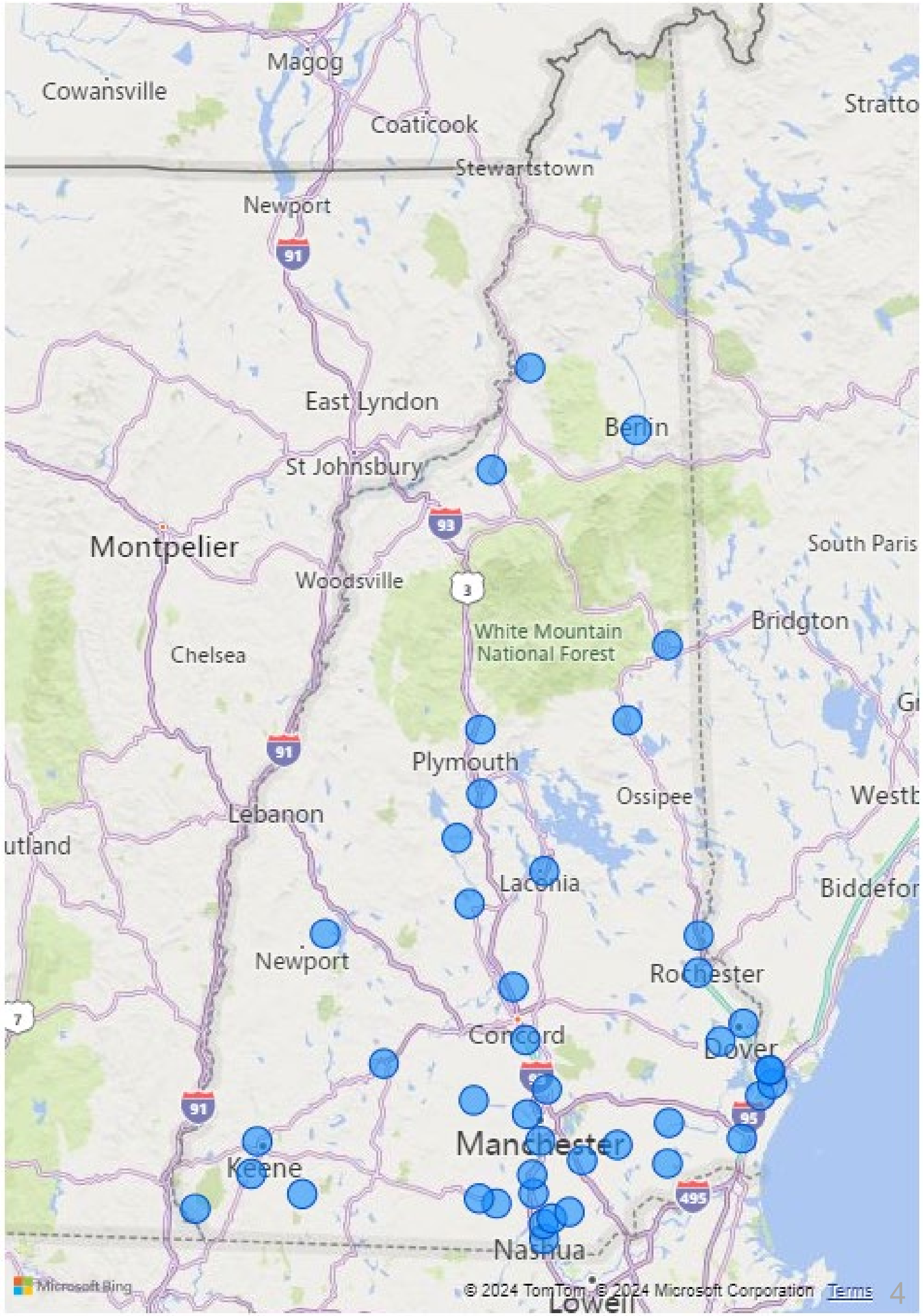
Overview of PSNH Distribution System

PSNH Distribution System

- 5 Planning Regions
  - Northern, Central, Eastern, Western and Southern
- 13 Area Work Centers with 2 satellite locations
- 123 Substations (including 50 bulk distribution stations)
  - 3 = 345-34.5 kV
  - 41 = 115-34.5 kV
  - 5 = 115-12.47 kV
  - 1 = 115-4.16 kV
- 12,300 circuit miles of overhead lines
- 2,100 circuit miles of underground lines
- 287,900 service transformers
- 539,000 customer accounts

Circuit Miles and Customer Count by Voltage

Voltage (KV)	12.47	13.8	3.74	34.5	4.16	8.32
Circuit Miles	6,084	16	79	4,863	2,875	388
# Customers	213,071	43	43,39	188,799	130,482	10,369



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See Bates Pages 02024-02026

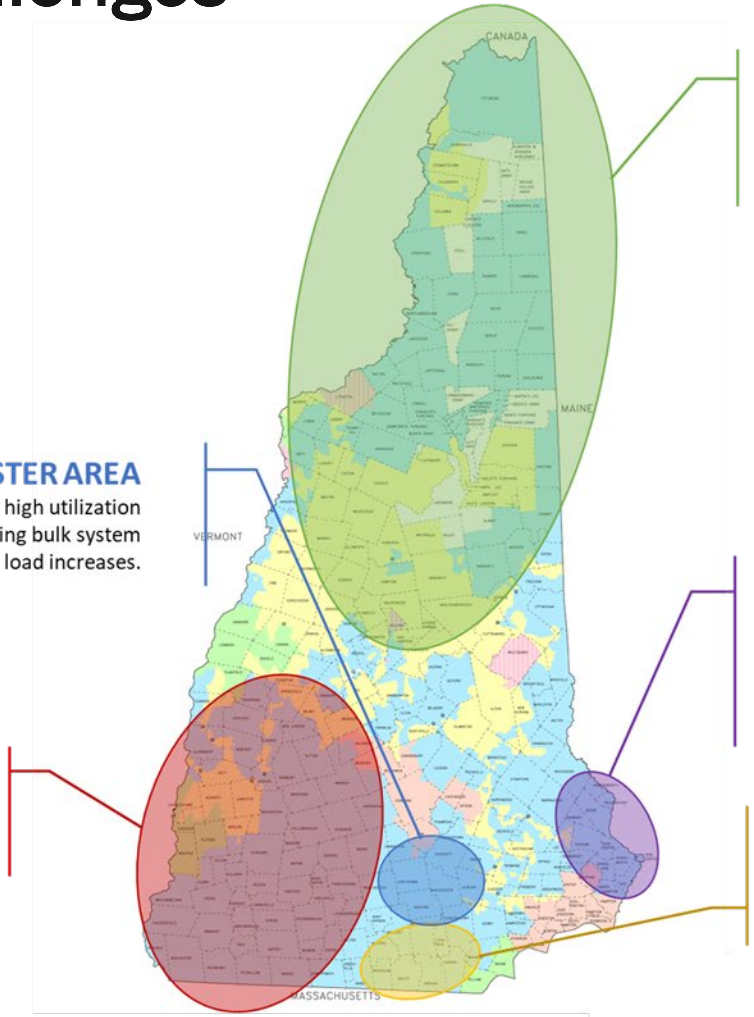
Planning Region Summary Data

- PSNH’s 539,000 residential, commercial and industrial customers create approximately **1.8 GW** of peak electric demand.

Region	Central	Eastern	Northern	Southern	Western
Customer Accounts*	119,100	111,100	101,100	136,400	74,800
Bulk Substations	8	11	12	12	7
DER Penetration	Low	Low	High	Low	High
Online DER (MW)	78	67	177	47	87
In-Queue DER (MW)	41	98	180	106	165
Peak Load 2023 (MW)	474	461	276	495	181
Customers per Substation	14,888	10,100	8,425	11,367	10,686
Online DER as % of Peak Load	16%	15%	64%	9%	48%
Online + Queued DER as % of Peak Load	25%	36%	129%	31%	139%

** Note: The term “Customer Accounts” refers to Eversource’s retail customers. This does not include customers of Unitil, nor members of New Hampshire Electric Cooperative supplied by Eversource’s bulk substation facilities.*

PSNH Planning Challenges



NORTHERN N.H.
Long 34.5 kV feeders due to geographically spread-out bulk substations challenge system reliability for serving Eversource customers and New Hampshire Electric Cooperative.

MANCHESTER AREA
Urban and suburban areas of Manchester have high utilization of substation capacity. Risk of maintaining bulk system reliability when accommodating large step load increases.

PORTSMOUTH & SEACOAST
Population migration in the last few decades has seen moves up the seacoast into Portsmouth and further into the Dover-Rochester area. Pease Tradeport is a major hub of commercial and industrial activity that continues to see growth.

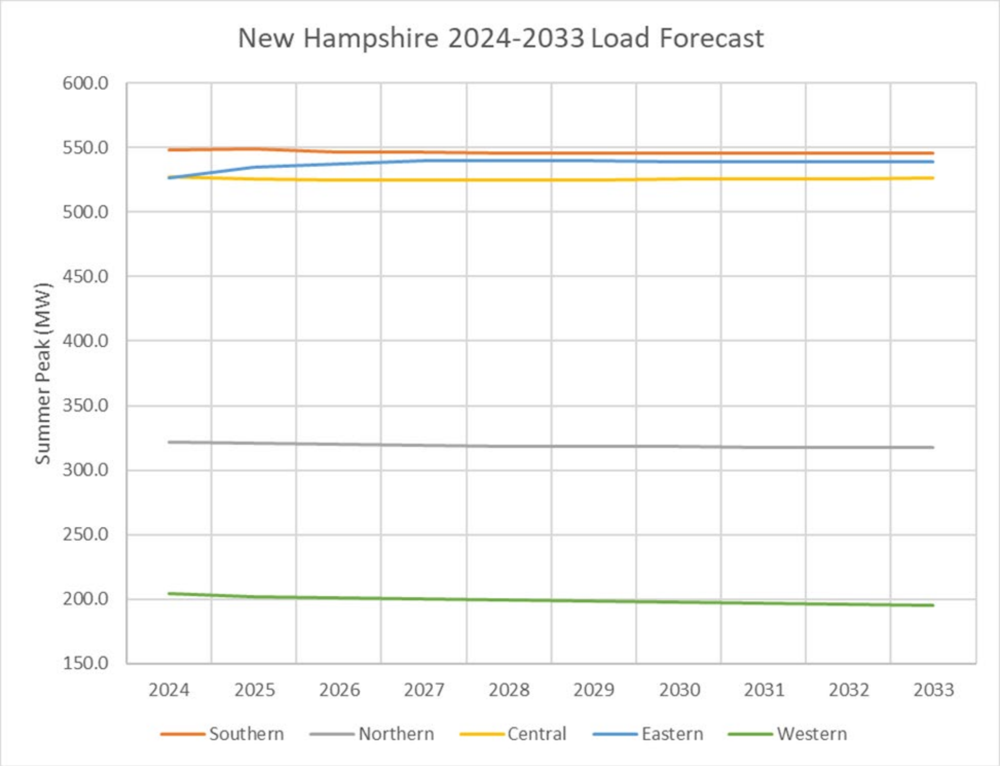
WESTERN N.H.
Long 12.47 kV and 34.5 kV feeders due to geographically spread-out bulk substations challenge system reliability.

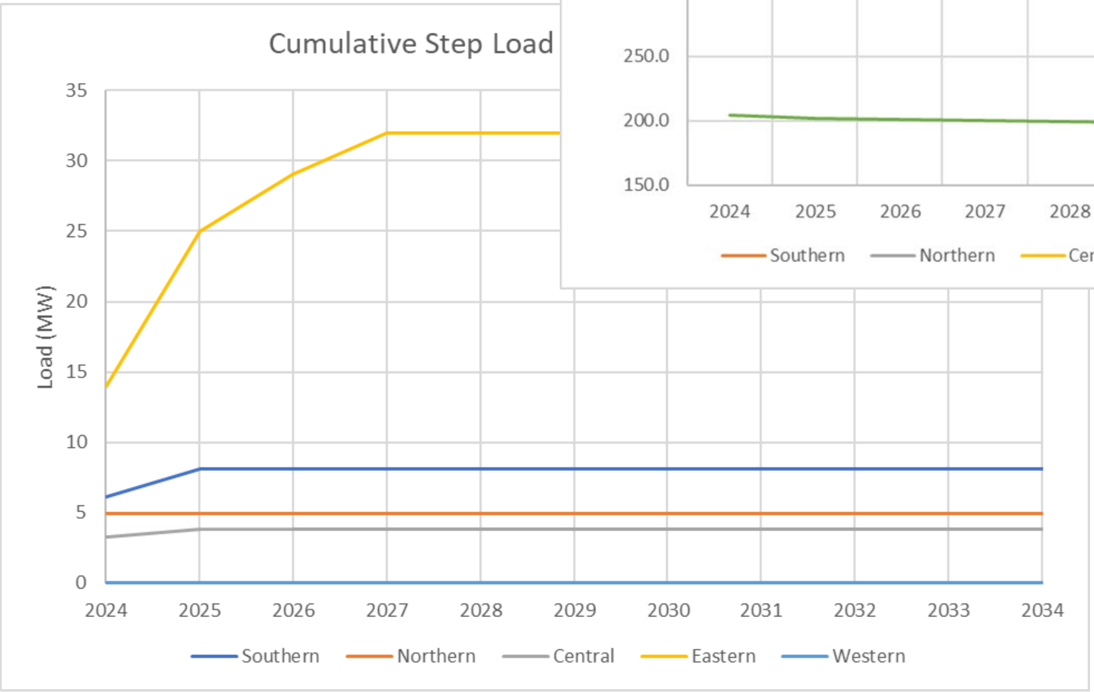
NASHUA AREA
The region sees steady redevelopment of former commercial and industrial properties into new commercial and residential uses.

Several different challenges exist across the PSNH service area. In localized areas, those challenges are more pronounced.

See Bates Pages 02032

Ten-Year Load Forecast

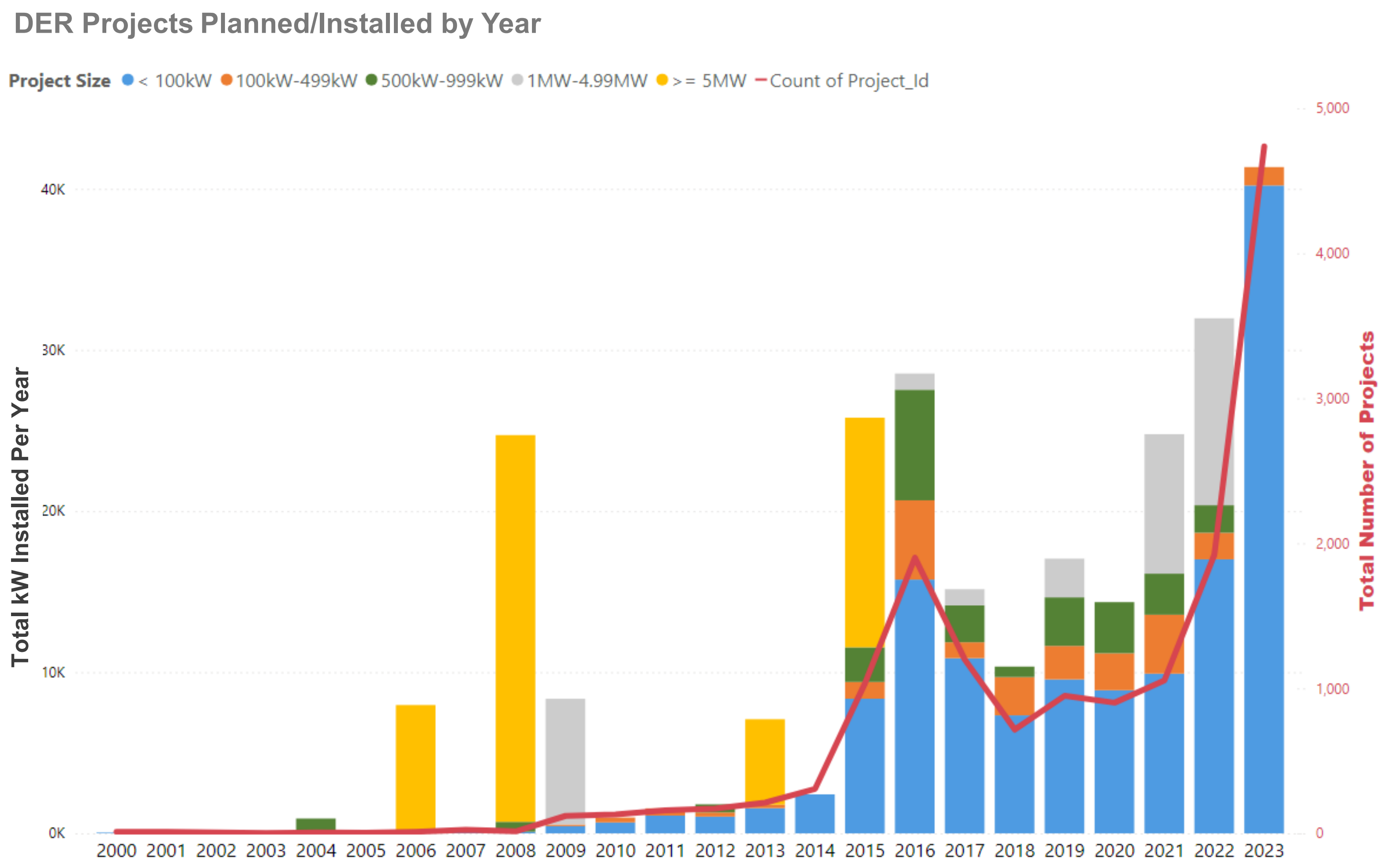




- Load growth (MW) may appear flat or negative at an aggregate level; while constraints exist in <u>localized areas</u>.
- “Step load” additions (mostly in the Eastern region), arising from economic growth, will drive 49 MW of increase from 2024 to 2033, e.g. redevelopment of Portsmouth’s downtown, new construction of multi-story, multi-use buildings.
- EV demand is the second largest new load, constituting 12 MW of residential charging (excluding large fleet charging operations and/or DC fast chargers).
- A sizable reduction to the net load comes from projected solar installations (-40 MW) and growth in energy efficiency program savings (-83 MW).

See Bates Pages 02120-02121

PSNH Growth in Installed DER, 2000 – 2024



- **491 MW installed since 2000**
- 2014 - 2016 and 2021 - 2024, saw significant increases in Interconnection Requests (IR)
- Vast majority of projects installed are less than 100 kW
- Projects ≤ 100 kW progress to Interconnection Agreement (IA) relatively quickly
- Larger, more complex projects, typically require a system impact study (SIS)
- **731 MW in the queue**

Regions with the least amount of native load, and highest potential for DER growth, tend to have the lowest total hosting capacity – innovative solutions may be needed

See Bates Page 02128

Distribution System Planning

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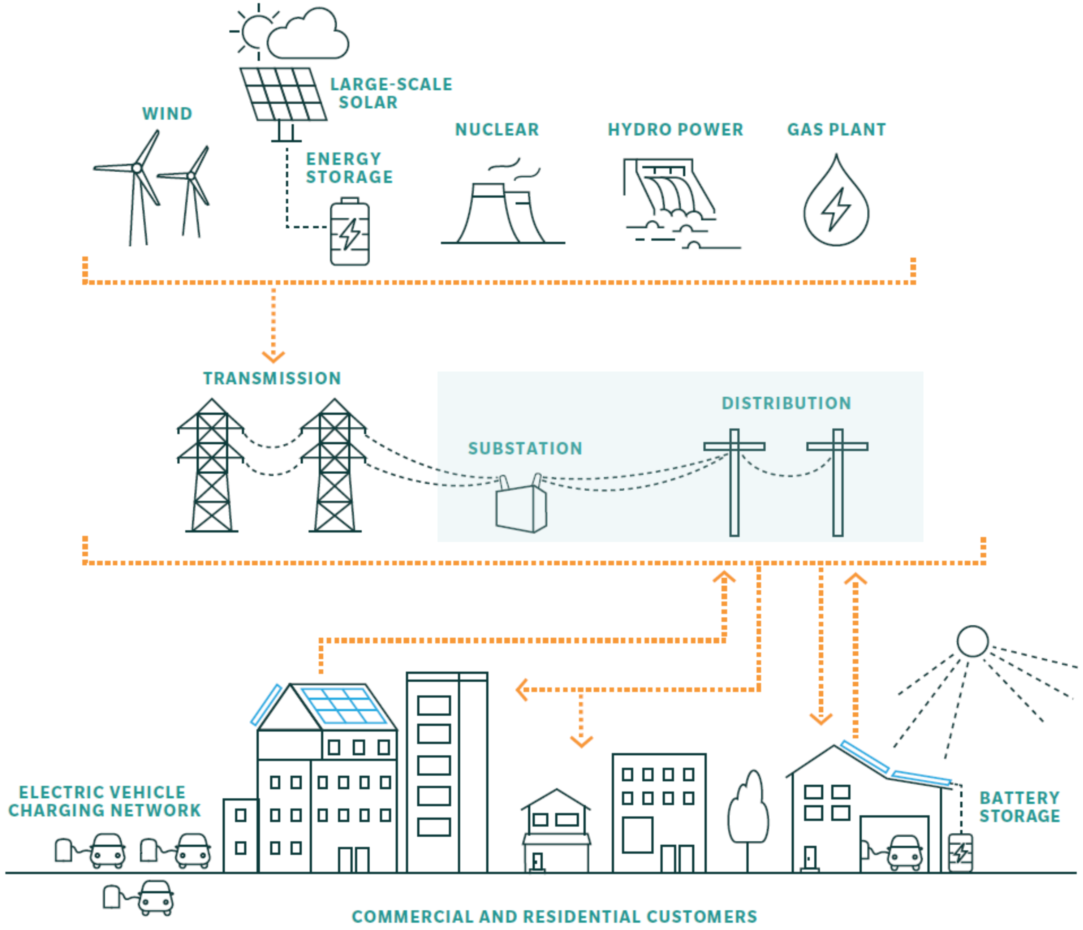
The Electric Grid

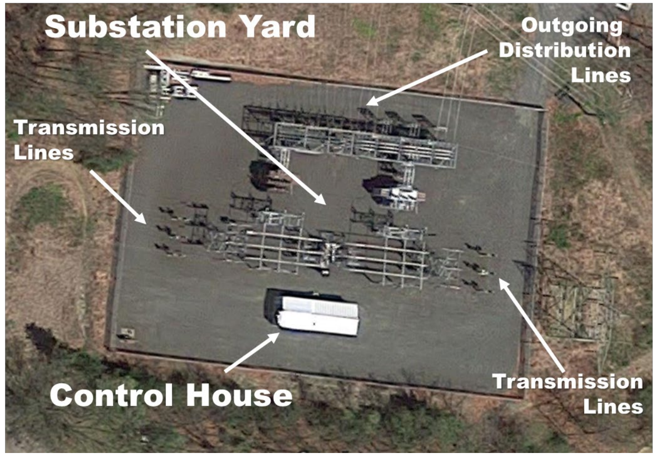
- Utility scale generation is interconnected across New England and even across the country by way of high-voltage transmission lines
- All of these lines networked together create a type of superhighway that moves electricity from the power plants to electric substations and local distribution systems that ultimately deliver power to homes and businesses
- The combination of these components is what we call the US electric grid



The distribution system is the backbone of a reliable Electric Power System (EPS)
… serving as an interface between the transmission system and customers

See Bates Page 02023

Bulk Distribution Substation Layout



Bulk substations are key components of the electric power system and essential elements in meeting residential and business customers’ demand for energy

See Bates Pages 02028-02030

Why do we plan?

- Need to plan ahead because it takes time to build capacity

T&D Level	Lead Time*
Transmission	10+ years
Bulk Substation	5+ years
Primary Feeder	2-4 years
Primary Lateral	1-3 years
Secondary/Services	2-12 months

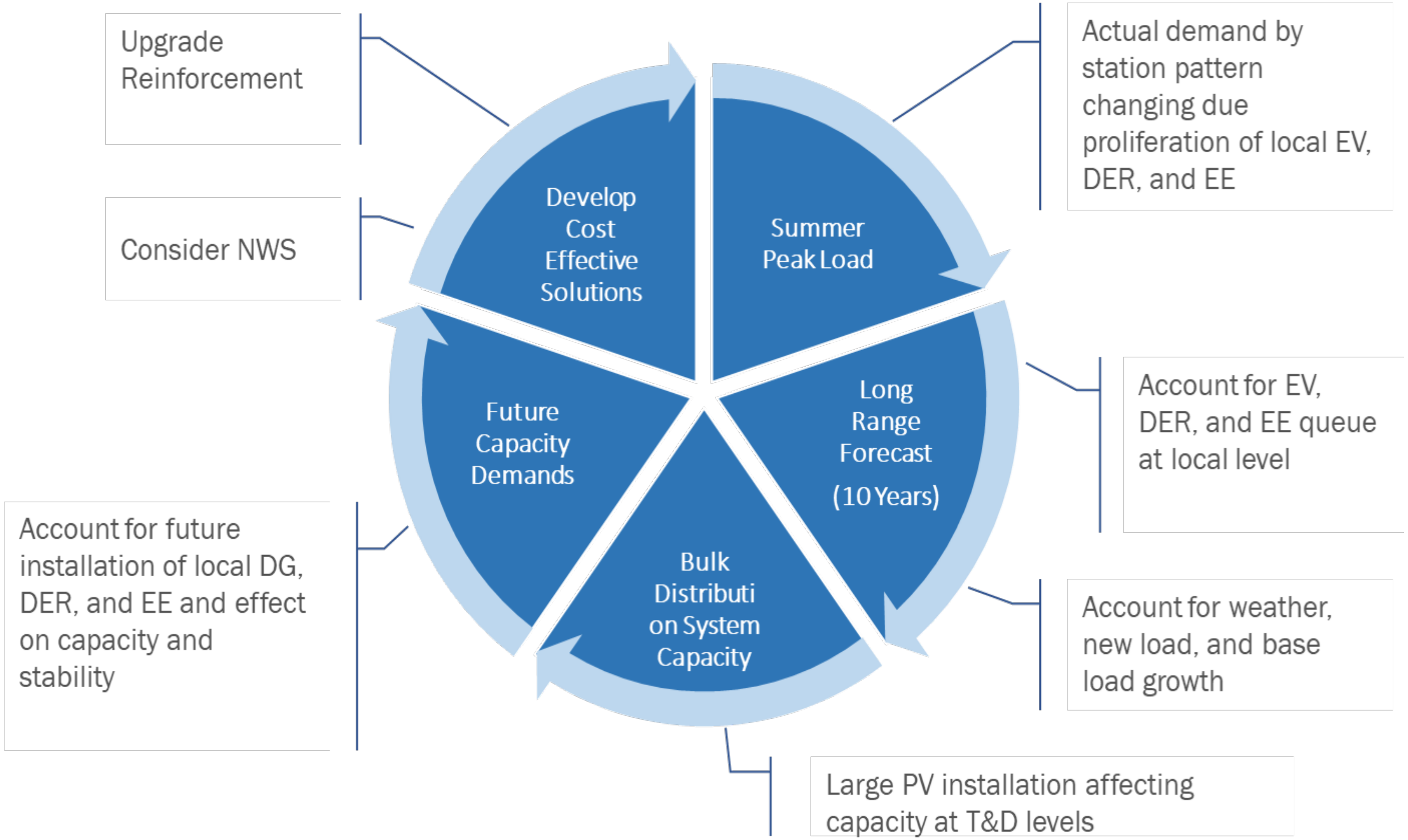
Effective planning accounts for lead time to deploy T&D assets in developing reasonable alternatives

* includes time to perform field audits, pole staking, environmental evaluation, etc. as well as procurement and siting/permitting delays

See Bates Page 02086

Breakdown of Distribution Planning Process

#1 Step = FORECASTING THE NET LOAD ON THE SYSTEM



Overall Guiding Principle:
Enable disciplined, cost-effective build-out, reinforcement and replacement of equipment and facilities to meet future demand with acceptable system performance

See Bates Page 02087

Tools & Methods for Distribution Performance Evaluation

Advanced tools and processes are used to assess impacts and plan the system to safely, reliably provide service for both electric load and DER installations.

- **Steady State Thermal Impacts**
  - Forward and reverse flow on transformers
  - Thermal overloads on station equip.
  - Thermal overloads on distr. feeders
- **Steady State Voltage Impacts**
  - Distribution feeder voltage violations
  - PQ /Voltage Flicker
  - Excessive LTC/ regulator/cap operations
- **Short Circuit Impacts**
  - Fault current at station bus and POI
  - Effective Grounding Concerns
- **Dynamic and Transient Impacts**
  - Risk of Islanding (ROI)
  - Transient Overvoltage, LROV, GFOV
- **Reliability and Resiliency Impacts**
  - Customers Interrupted (CI)
  - Customer Minutes of Interruption (CMI)

See Bates Page 02090

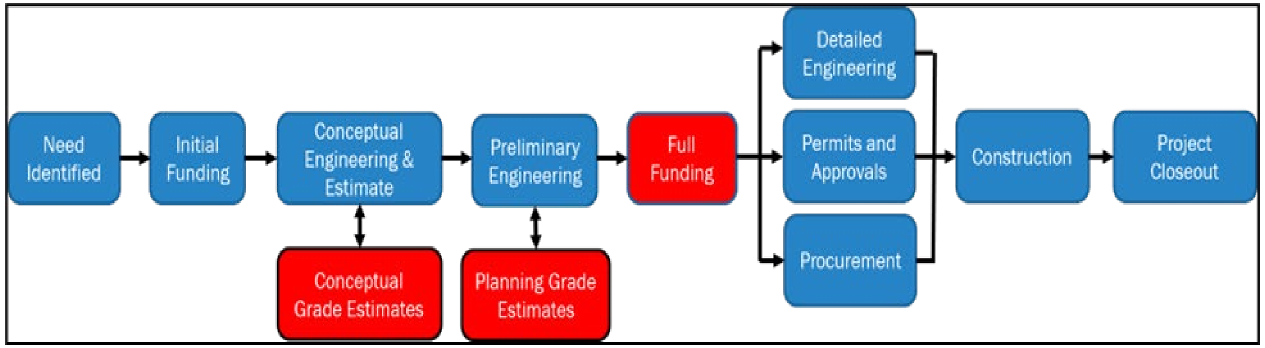
Development of Distribution Solutions

- **Planning Objectives –**
  - Provide adequate reliability and resiliency to disruptive events.
  - Ensure sufficient capacity to meet future demand and service needs.
  - Satisfy voltage and power-quality requirements within applicable limits.
  - Serve all customers safely.

- **Data Analytics and Tools** – leverage traditional and non-traditional inputs (GIS, solar irradiance, socio-economics, travel patterns, parcel data and others), along with cutting-edge tools, to develop long-term view of system need.

- **Solution Alternatives** – develop solutions with varying levels of complexity:
  - Reconfigure the system to balance load
  - Replace/upgrade limiting equipment
  - Add new equipment or expand system capacity
  - Construct or apply Non-Wires Alternative Solutions
  - Build new substation

- **Solution Selection** – complex and iterative process involving several groups to select preferred solution in compliance with internal and external stakeholder requirements.



See Bates Page 02091-0293

Forecasting Process - Adjustments to Reported System Peaks

Final reported peak

Reported Net Station Peak

Transfer Correction

Any other generation

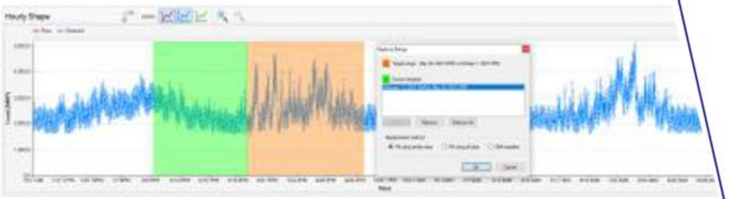
Large Solar Generation at time of peak

Small Solar Generation at time of peak

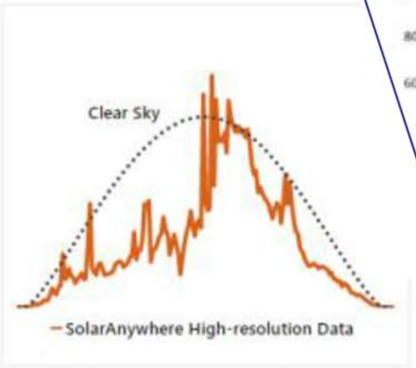
90/10 weather adjustment

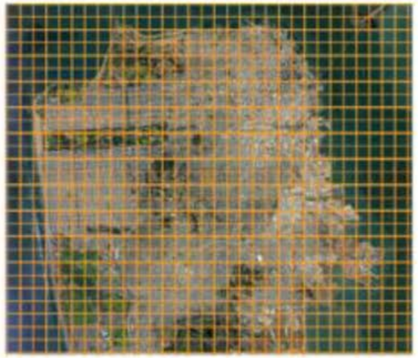
Reported Weather Normalized 90/10 Gross Station Peak

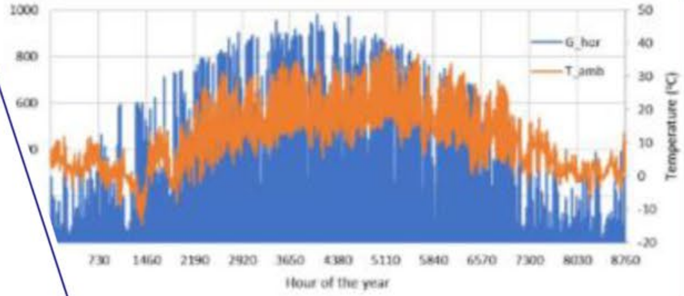
Historic SCADA readings on all large generation installations



Historic, satellite-based weather data to calculate non-metered solar output



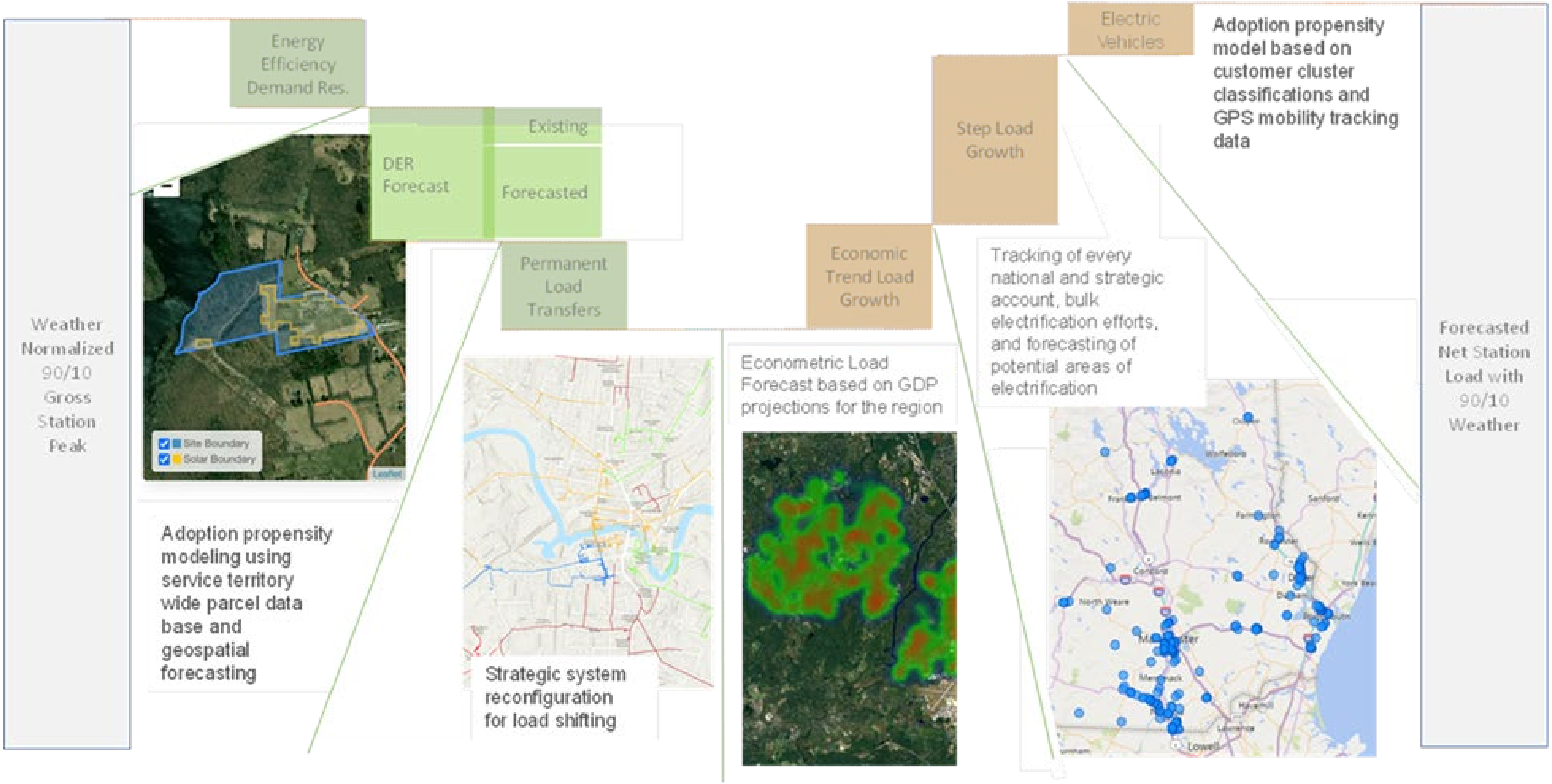




Historic, satellite-based weather data to calculate non-metered solar output

See Bates Page 02107

Forecasting Process - Adjustments to the Econometric Trend

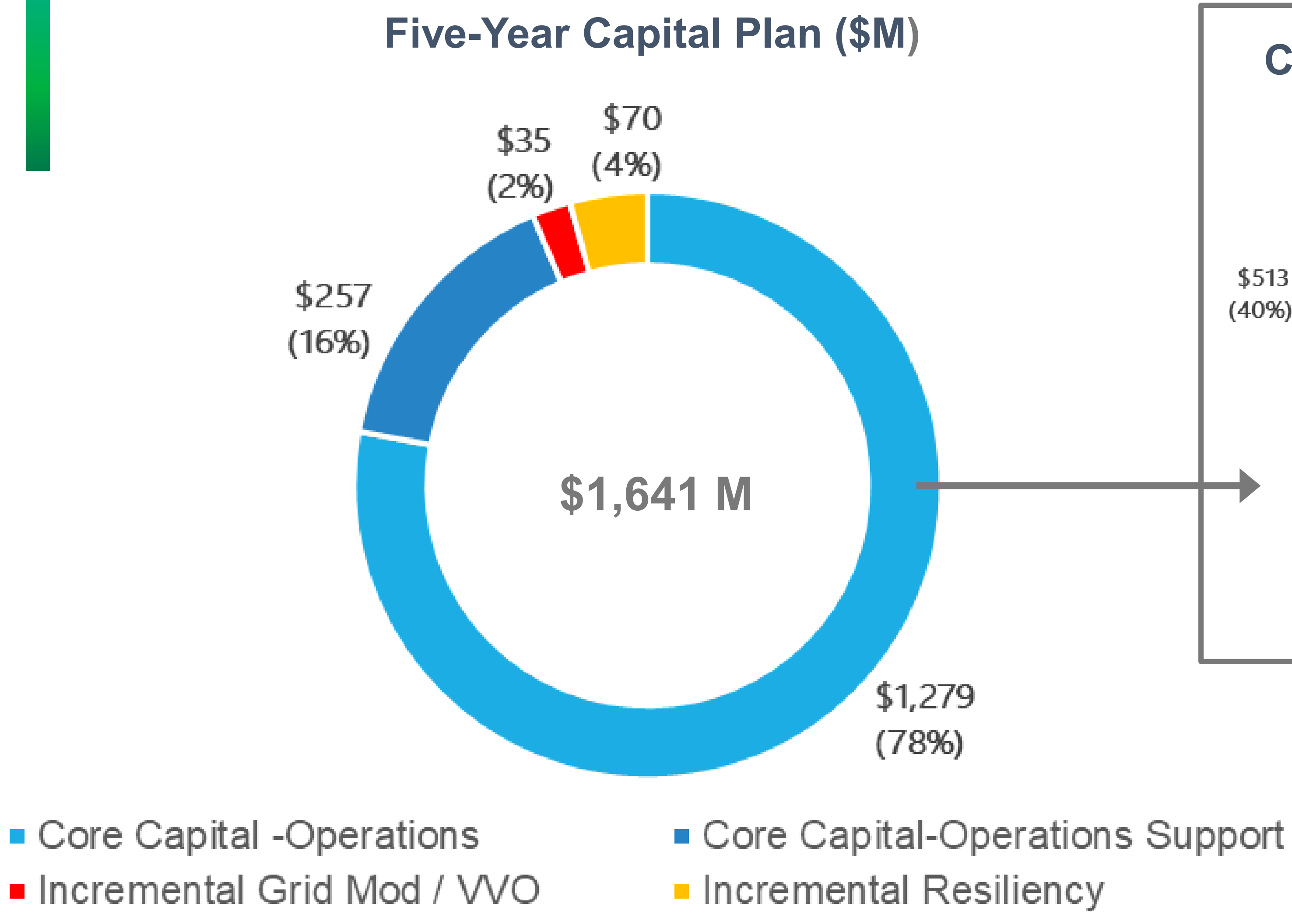


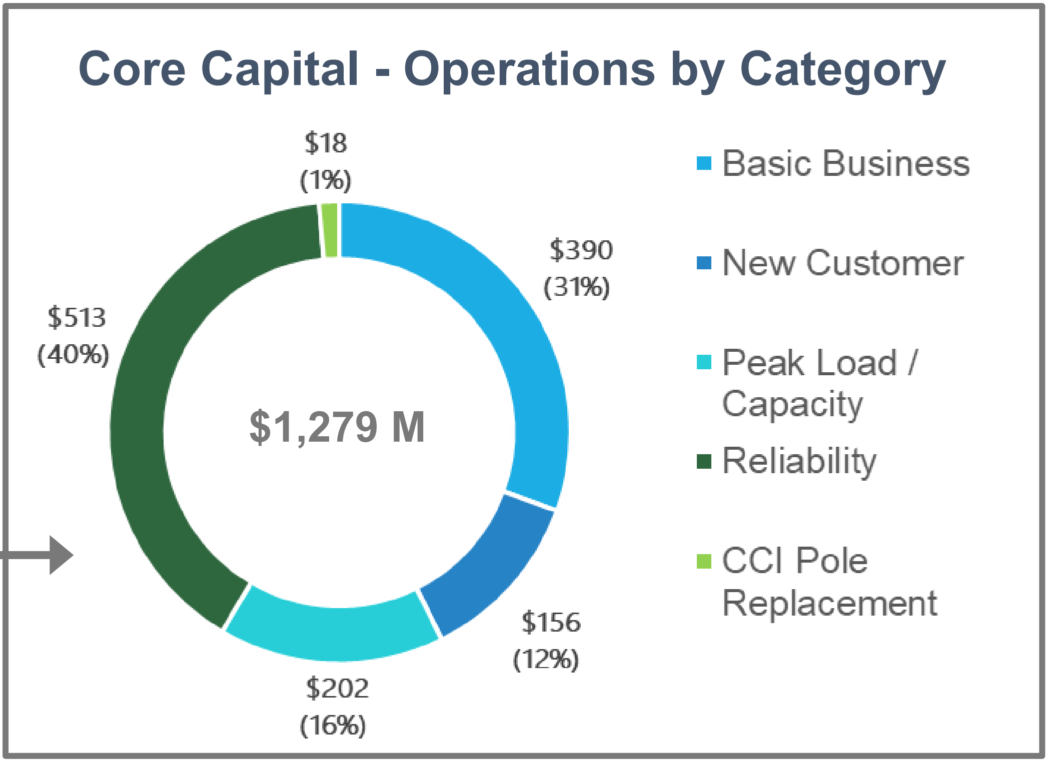
See Bates Page 02108

Capital Expenditure Summary

2025-2029 Capital Investments ($M)

EVERSOURCE





- **Core Investments** – Capital projects carried out for Electric Operations consistent with PSNH's long-range plan; funded through base rates, with incremental year-to-year investments after the rate case through a capital mechanism.
- **Resiliency and Grid Modernization:** Proposed capital projects to harden the distribution system against climate change threats; improve control room technology; optimize the system through voltage management; and provide addition planning tools for future forecasting.

See Bates Page 02172

New Hampshire Distribution System

Age and Condition Assessment

TRC conducted a distribution system assessment in accordance with the Docket DE 19-057 Settlement Agreement, reviewing the following areas pertaining to reliability and resiliency improvements:

- Use of distribution-class steel poles as a standard in off-road right-of-way
- Use of Class 2 wood poles as a standard in road-side primary distribution lines
- Use of spacer cable as a standard for overhead conductor
- Use of fiberglass crossarms
- Planning methods for line relocation and reconductoring activities
- Substation transformer and circuit breaker replacement processes
- Vegetation management activities, including Enhanced Tree Trimming, Enhanced Tree Removal, and Right-Of-Way Clearing, in addition to Scheduled Maintenance Trimming

Key Findings

Figure ES-1-1. Summary of Key Findings and Recommendations by Study Topic Area

Topic Area	Key Findings	Recommendations
System Condition	• **Many distribution components are beyond their expected life and require replacement to maintain system reliability and resiliency.** • **Substantial numbers of wood poles, circuits of primary conductor, substation breakers and substation transformers are at the end of life.** • **Wood poles are structurally overloaded due to their age and number of attachments.** • **Many circuit lines in the ROW are inaccessible due to location and difficult to maintain.** • **Trees and canopy are in close proximity to distribution system making the lines vulnerable to outages.**	• **Accelerate replacement of aged equipment (poles, conductor, substation breakers & transformers), with a systematic plan for each equipment type, based on system criticality and age.** • **Replace wood poles that are structurally overloaded 90% or more, with the properly sized poles in the next 10 years.** • **Identify candidate lines for relocation to roadside and develop 5-year plan to rebuild.** • **Increase vegetation management and spacer cable installation for vulnerable lines.** • **Consolidate current resiliency/hardening efforts into an overarching program following the decision framework outlined by the Department of Energy.**

Reference: Eversource New Hampshire Distribution System Assessment, TRC Companies, 5/28/2021.

Key Findings

Figure ES-1-1. Summary of Key Findings and Recommendations by Study Topic Area

Topic Area	Key Findings	Recommendations
Substation Transformers	• **Standardizing substation transformer sizes can provide benefits for streamlining inventory and reducing event response time.**	• **Standardize substation transformer sizes wherever possible based on voltage class to allow for greater efficiency in maintaining stock of fewer transformer sizes and flexibility in responding to contingency events and coordination with neighboring state service areas.** • **Continue to assess to determine when circuit breakers should be used in place of circuit switchers for operational and reliability benefits.**
Distribution Planning	• **Eversource conducts distribution planning to maintain system operations within established operating criteria.** • **Engineers develop solutions to address capacity, power quality, and reliability concerns based on historical performance data and forward-looking forecasts.** • **Line relocation and reconductoring are two options to address reliability issues.**	• **Establish a tracking program to compare historical outage data for line segments for 3-5 years (as data is available) and then report annually on that segment post-improvement. Such a system will document the improved reliability and resiliency delivered by relocation and reconductoring projects.** • **Reduce the number of feeders without tie capability to allow for circuit reconfiguration and load pickup throughout the system.** • **Maintain awareness for distribution project cost increases that may arise as projects are delayed.**

Reference: Eversource New Hampshire Distribution System Assessment, TRC Companies, 5/28/2021.

Key Findings

Figure ES-1-1. Summary of Key Findings and Recommendations by Study Topic Area

Topic Area	Key Findings	Recommendations
Steel Poles	• Benefits of steel poles include improved strength, reduced likelihood of catastrophic failure, and lower maintenance costs. • Steel poles have twice the expected useful life of an equivalent wood pole. • While upfront costs are higher, the improved longevity of steel yields a lower total lifecycle cost compared to wood poles.	• Given lower lifecycle costs and difficulty in patrolling and replacing remote right-of-way assets in the event of a failure, continue to use steel poles as the standard in these environments. • Establish a proactive program to identify and replace five circuit miles/year of wood poles in the ROW with steel, in areas susceptible to damage or failure.
Class 2, Wood Poles	• Class 2 wood poles can withstand 60% greater force than smaller-diameter class 4 poles, improving outcomes during tree strikes or high winds. • Class 2 wood poles have marginally (2-4%) higher costs than equivalent Class 3 poles. • At current failure rates, if 8-9 poles (~5%) did not fail due to use of stronger Class 2 poles, incremental costs would be negated.	Continue use of Class 2 wood poles due to low additional costs and strength improvements in severe weather scenarios

Reference: Eversource New Hampshire Distribution System Assessment, TRC Companies, 5/28/2021.


Thank You!
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