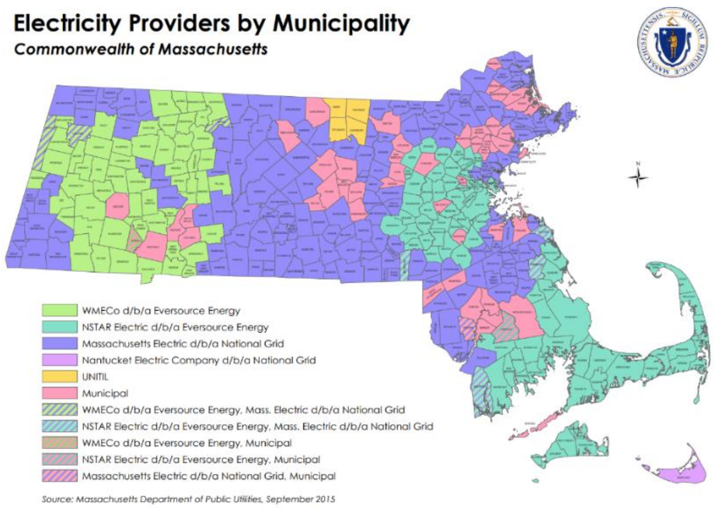
FINANCING THE TRANSITION: BACKGROUND

Q. How is the electric utility industry organized in the Commonwealth?

Massachusetts has three investor-owned electric distribution companies (EDCs) and 41 municipal utilities, as shown in the map below. Over 90% of electricity consumers in the state[1] are located in the EDCs' service territories (e.g., National Grid, Eversource, and Unitil).



For more than two decades in Massachusetts, individual electricity consumers served by EDCs have had the option to purchase their power supply from a competitive retail power marketer or from the utility's "basic service" (previously called "default service") electricity supply, which is typically procured by solicitation from competitive wholesale suppliers. Whether a customer purchases their supply from a competitive retail provider or takes basic service, their power is delivered to them by the local EDC.[2]

Massachusetts also allows municipalities located in EDCs' service territories to establish "municipal aggregation" programs in which the municipality contracts with a competitive supplier to offer retail electricity supply to electricity customers in the community that have not opted out of the program. Currently, approximately 195 municipalities have approved municipal aggregation programs.[3] The local EDC provides for the local delivery of this power to customers as well.

As of 2022, nearly 60% of customers served by Massachusetts EDCs purchase competitive electricity supply either directly from a competitive retail supplier or a municipal aggregation, as opposed to taking basic service. Large electricity customers (e.g., many commercial and industrial customers) often purchase electricity from a competitive retail supplier.

Q. How does the electric grid work and what is the local electric distribution system?

Transmission Owners (TOs), which are corporate affiliates of the EDCs but not regulated by Massachusetts, operate and maintain an electric network consisting of thousands of miles of electric transmission lines that carry electricity long distances at high voltage levels to transmission substations, where EDCs interconnect to the transmission system. From this point of interconnection, the EDCs distribute power to distribution

[1] Statistics in this section are from the Energy Information Administration's 861 database, whose most-recent finalized data are for 2022.

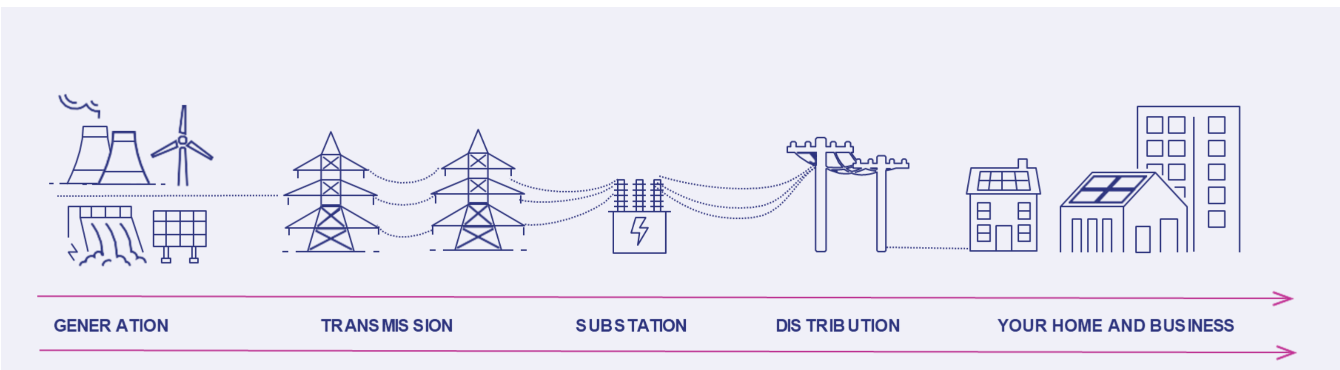
[2] Customers of municipal utilities in Massachusetts typically do not have the option to buy power from a competitive retail power marketing company and must buy bundled electricity service from the local municipal utility. The rates and terms of service of municipal electric utilities are established by their boards of directors rather than by state utility regulators at the Massachusetts Department of Public Utilities.

[3] https//www.mass.gov/news/dpu-enhances-municipal-aggregation-process

substations which step down this power to a lower, distribution-level voltage. Once this power is at a lower voltage level, it is carried across the local electric distribution system.

This local electric distribution system is composed of tens of thousands of miles of smaller electric distribution lines that are supported by millions of poles and approximately 450 strategically located distribution substations. Substations play a pivotal role in stabilizing the entire electric network and maintaining safe and reliable service and must be located close to the load they serve. These substations can safely operate indoors or outside and do not emit pollutants that impact local air quality.[4] Once power is stepped down further to appropriate voltage levels, electricity is distributed across a series of lower voltage circuits or wires, which run overhead or underground (largely depending upon land-use developments and densities). This power is then stepped down again at smaller transformers close to homes and businesses (e.g., on top of utility poles) and safely delivered to customers.

Today's Grid



Q. How is the grid changing and what investments are being proposed?

The way electricity is produced, delivered and consumed is changing as policies, programs and technological changes are implemented in support of the Commonwealth's climate and clean energy mandates and regulations. Consistent with the pathways to decarbonization established in the *2050 Clean Energy and Climate Plan*, additional capacity will be made available on the transmission and distribution systems and will place more reliance on the local electric distribution grid. To meet the climate and clean energy goals of the state, the electric distribution grid will need to 1) be better able to connect and optimize more clean energy, including solar, wind and storage, 2) support increasing amounts of electrification from heating, cooling and transportation, and 3) be more resilient to a changing climate.

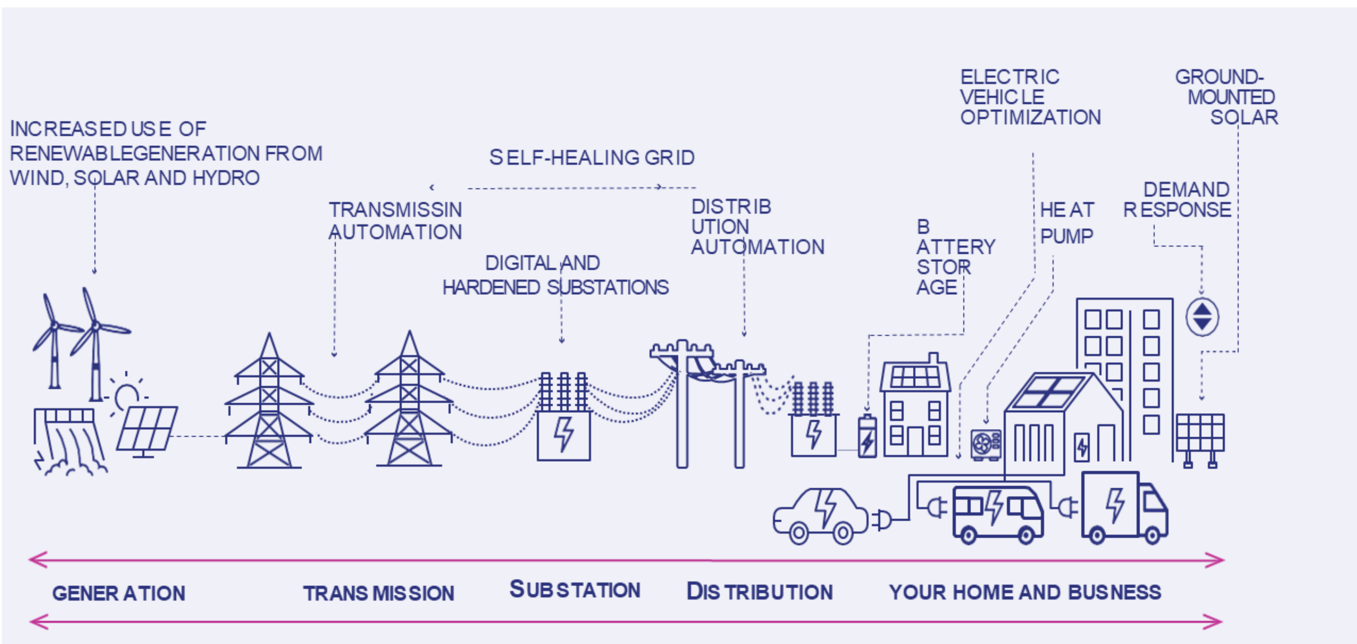
[4] The primary insulating medium for substations with Gas Insulated Switchgear (GIS) is sulfur hexafluoride (SF6); this allows for compact design, among other attributes. SF6 is also a potent greenhouse gas. Massachusetts regulates SF6 from GIS through 310 CMR 7.72 and establishes a maximum annual leak rate of 1%. Annual reporting to Massachusetts DEP is required by GIS owners.

FINANCING THE TRANSITION: BACKGROUND

In January 2024, the EDCs filed Electric Sector Modernization Plans (ESMPs), as directed by the *2022 Climate Law – An Act Driving Clean Energy and Offshore Wind*. The ESMPs are strategic plans aimed to improve grid reliability and resiliency in anticipation of more frequent and extreme weather events and designed to prepare the grid for rapid deployment of renewable energy sources, support energy storage, and enable electrification technologies essential for reducing carbon emissions, including in buildings and transportation.

Each EDC developed and relied on five- and ten-year demand forecasts to determine necessary investments to meet the climate and clean energy goals and mandates. The EDCs' proposed ESMP-related investments for the next five years total approximately $5 billion and include projects to increase the flexibility and capacity of the electric distribution grid, expand customer programs targeting distributed energy and electrification, and add technology to optimize and automate grid operations, reduce demand, and manage costs to ratepayers. The Massachusetts Department of Public Utilities (DPU), which regulates the EDCs, approved these strategic plans on August 29, 2024 and will launch further proceedings on cost recovery.

Tomorrow's Grid



Q. Who regulates electricity rates (prices) in Massachusetts?

Electricity rates in Massachusetts have two primary components: delivery (which is composed of distribution and transmission costs) and supply (which is the cost of retail electric supply – or the electric commodity itself). The DPU regulates the prices and other terms and condition of EDCs' electric delivery service, which is the cost of service for local delivery.

FINANCING THE TRANSITION: BACKGROUND

The Federal Energy Regulatory Commission (FERC) regulates the cost of service for transmission. ISO New England is the Regional Transmission Operator and administers a transmission planning process subject to FERC's jurisdiction. ISO New England has operational control over, but does not own, the TOs' transmission assets. ISO New England leads the process for planning new transmission system upgrades while the TOs maintain planning for replacing or refurbishing existing assets. The TOs' revenues in New England are recovered under a FERC-regulated formula rate tariff that compensates TOs based on their cost of service and a FERC-approved return-on-equity for transmission. The cost of transmission is allocated to each EDC under the ISO New England tariff on a monthly basis, generally according to the EDCs' share of load in the hour of the system peak for the month, with additional localized costs required to operate the system in a given area. The EDCs then collect those costs from customers under their tariffs as a "pass-through" charge approved by the DPU.

The regional, centralized wholesale electricity markets in which power plant owners participate[5] are administered by ISO New England under market rules that are regulated by FERC. Retail electricity suppliers bid into the centralized markets to offer to purchase energy or capacity, or they enter into power purchase agreements outside of the markets. The combination of those transactions results in the power supply price (e.g., the commodity or retail electric supply costs) that customers receive either through 1) competitive retail suppliers directly, 2) through municipal aggregation programs, or 3) from EDCs via basic service rates approved by DPU. Thus, electricity prices paid by consumers reflect these three core components, as shown in the figure below, with regulation varying between federal and state regulators:

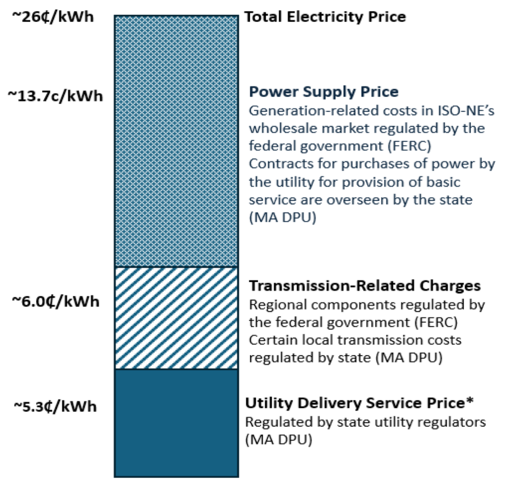
1. The **power supply price reflects the market-based prices of power generation**. The prices charged to consumers tend to reflect a blend of power generated from various sources of electricity throughout New England and purchased on the competitive wholesale market administered by ISO New England and overseen by FERC, and/or through bi-lateral contracts between buyers and sellers of energy. For basic service, the EDCs procure electricity twice a year through a DPU-approved, competitive solicitation process and pass the costs they are charged for this power through to customers that take basic service, without profit or mark up.[6]
2. The **transmission cost component reflects the TOs'** costs associated with constructing and maintaining higher-voltage, regional transmission facilities. These costs are regulated by FERC, allocated to the EDCs, and collected from customers in the retail rates that are approved by DPU.
3. The **local delivery service price component reflects** the EDCs' costs to provide local grid services, including construction, operation and maintenance costs, and the cost of several state-mandated programs that benefit consumers (e.g., Mass Save programs, SMART program). These rate elements are subject to regulation by the DPU, which also oversees rates for transmission below certain voltage levels that provide service to the utility's own retail customers.

[5] On an operational basis, all power plant suppliers connected to or flowing power over the high-voltage electric system must offer electricity into that market each day, even if those power plants also sell power through contracts that govern the financial arrangements between wholesale power suppliers (e.g, power plant owners) and wholesale power purchasers (e.g., retail power marketers, municipal power aggregators, and distribution utilities providing basic service).

[6] EDC renewable energy credit costs are included in the power supply price.

FINANCING THE TRANSITION: BACKGROUND

Massachusetts Electricity Prices to Retail Consumers
(2022 data – average of electricity sales by investor-owned utilities)



* Local delivery price also includes various surcharges (e.g., for electric vehicle charging investments, renewable energy credits, energy efficiency programs) for state-mandated utility programs..

Data: Energy Information Administration 861 data for electric utilities selling bundled and unbundled electricity; with rough estimate of average local and regional transmission charges.

In 2022, the all-in price of electricity for EDCs' customers in Massachusetts was approximately 26 cents per kilowatt-hour (kWh). In that year, approximately 20% was for local delivery services, 23% was for transmission costs, and 57% was for power supply. In 2023, however, with a lower price for wholesale power supply in New England (i.e., roughly 8 cents/kWh in 2023 versus nearly 14 cents/kWh in 2022[7]), electricity costs ended up lower largely due to fluctuations in the cost of generation.

Q. How are customers' local delivery service rates determined under DPU regulation?

EDCs, like National Grid, Eversource and Unitil, may change their rates only after review and approval by the DPU. Rates for delivery service are reviewed and approved through formal administrative-law proceedings (e.g., rate case dockets) in which the utility and other parties provide evidence for consideration by the DPU and in which the parties cross-examine witnesses and the DPU issues orders describing its findings and determinations.

In Massachusetts, rates traditionally reflect the utility's cost to provide service during a "test year," with rates that vary by type of customer (e.g., residential versus commercial versus industrial) and by type of service (e.g., time-of-use rates versus fixed service). The cost-of-service rates take into account (a) expenses (such as labor, fuel used to operate utility trucks, annual rent in buildings), on which the utility is not allowed to charge a mark-up for profit, and (b) investments (such as the cost to construct, finance and maintain power lines, trucks, computers, buildings and other equipment with a useful life longer than a year), on which the utility has the opportunity to earn a profit.[8]

Once the utility makes an investment and it becomes operational (e.g., is "used and useful" to provide utility service), the utility puts forward a request in its rate case that it be allowed to include that investment as part of its "revenue requirement" (i.e., its cost to provide utility service). If determined by the DPU to be a prudent investment, then the dollar value of that investment is included in the utility's test year "rate base," a year's worth of depreciation expenses related to the asset is included in the revenue requirement, and the utility is allowed to recover a return on the undepreciated amount of assets in the rate base.[9] The DPU sets the allowed rate of return to incorporate into the new rates.

[7] ISO New England, *2023 Annual State of the Market Report*, p. 14 https//www.iso-ne.com/statistic-assets/documents/100011/2023-annual-market-report.pdf

[8] The DPU's *2023 Annual Report* describes the ratemaking process. Https//www.mass.gov/doc/dpu-annual-report-2023/download

[9] The rate base changes over time as new investments are made and deemed prudent, and as prior investments are depreciated over time (thus reducing the size of the undepreciated portion of the investment).

In the rate case, the DPU decides which expenses and already-made investments to allow into rates (and whether to adjust amounts originally proposed by the utility). The rates are designed so that expected sales of electricity will produce revenues sufficient to cover the utility's costs (the revenue requirement). Variations in sales levels (up or down relative to the expected levels) can produce higher or lower revenues,[10] and unanticipated variations in costs associated operations, maintenance, and capital can impact overall costs; thus, the EDCs return on investment is not guaranteed.

Q. How do regulators set the allowed rate of return (or profit) for EDCs' investments and how do utilities raise capital for their investments?

Utilities raise capital to finance their investments through two sources: *debt*, which is borrowed from commercial lenders and others through loans and the issuance of bonds, at predetermined rates; and e*quity*, which involves the *s*ale of ownership shares in a company through the issuance of stock.

When the DPU determines the amount of dollars to include in the utility's revenue requirement and customer rates in a rate case, regulators determine their preferred "capital structure" (i.e., the relative values of debt and equity), the cost of debt (e.g., typically based on the blended cost of debt incurred by the utility) and the allowed return on equity (e.g., typically based on regulators' views about the costs experienced by other comparable companies in raising equity in capital markets).

Because debt is typically less risky than equity (e.g., creditors have a higher priority in repayment ahead of shareholders), debt has a lower cost of capital. Shareholders generally expect a higher return (on their investment). The DPU establishes the cost of capital by determining the ratio of debt and equity (e.g., 50%/50%) and the allowed cost of capital of each component (e.g., 6% debt; 9.5% equity), with a blended cost of capital applied to the return an EDC is allowed to earn on capital investments (e.g., 7.25%). This is incorporated into the utility's revenue requirement which, along with expenses, establishes the level of revenue recovered through customer sales to support utility operations and raise capital.

The utility raises capital in credit and equity markets. Its cost of debt issued in the future will be affected by rating agencies' (e.g., Moody's, Standard & Poor's) views about their credit risk, which is impacted by the rates approved in a rate case. The actual cost of equity will be affected by the EDC's management of its costs, prudency of investments, and other factors affecting performance in the equity (e.g., stock) markets. The "allowed" return included in the EDC's rates is no guarantee for its actual return. The actual return will depend on the utility's performance and ability to manage costs. Further, unless interim adjustments or prospective capital plans are allowed, EDCs' rate of return typically decreases over time as the utility continues to make investments that are not incorporated into its rates. This is known as "regulatory lag" (i.e., the time between the incurrence of a cost and when the cost is recovered through rates). Traditional regulatory thought is that some level of "regulatory lag" is necessary to provide an incentive for an EDC to manage its costs. Conversely, regulatory lag can impact the attractiveness of investing in a utility.

[10] Currently, revenue decoupling helps mitigate fluctuations in revenues.