Residential EV TOU Rate Design Supplement

The calculation of residential electric vehicle time-of-use (EV TOU) rates proposed by Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource or the Company) in this proceeding are based on marginal costs for the distribution, transmission and generation components of service. The development of these costs and determination of corresponding TOU periods are provided in the document, "Marginal Cost Analysis Supporting the Design of the Company's EV TOU Rate", provided on pages 4-10 of this attachment. The Company has established three TOU periods for purposed of the proposed design: Peak, Mid-Peak and Off-Peak, with a five-hour peak period commencing at 2 p.m. for all weekdays except holidays; a mid-peak beginning at 7 a.m. and ending at 11 p.m. each day, except for peak period hours; and all other hours being off-peak.

In designing the proposed EV rate, the Company applied marginal cost differentials between each period, utilizing appropriate volumetric billing determinants for each time period and setting prices for each component of service that resulted in design that is revenue neutral to corresponding rates applied in Residential Rate R. For distribution service, the volumetric rate design revenue target allowed for separating the portion of the existing TOD monthly customer charge associated with the local facilities costs and including such costs in the volumetric rate design. This provided an important price signal related to local facilities marginal costs while allowing remaining distribution system costs that exhibit time-varying characteristics to be evaluated and priced on a TOU basis.

While the Company relies on the price paid to wholesale suppliers for generation service, as well as the separately priced transmission service rate for transmission service, the Company relied on marginal cost analysis for each of these services along with distribution marginal costs of service, to inform time-differentiated cost characteristics of costs and prices for these services. The time-differentiated marginal costs for these three major components were utilized in setting energy, or volumetric, prices for each of the periods in the Company's proposed EV rate design.

Detailed calculations of TOU prices for each component of service under this proposal are shown in the formulas provided on page 3 of this attachment (which is also being provided as an Excel file titled Workpaper EAD-1). This work paper shows the marginal costs, billing determinants and rate design targets by time period and by component of service utilized in calculating proposed rates. The calculations in this workpaper were performed to ensure that an appropriate marginal cost differential between each period is achieved, recognizing these differentials vary by component, and are each set based on the defined TOU periods. As further discussed on pages 4-10 of this attachment, the time periods utilized in these calculations reflect the best fit of marginal costs across all three components of service.

The calculation of rates by TOU uses marginal cost differentials between periods, on a revenue-neutral basis with the volumetric-related revenue requirement for each component. The customer charge is reduced when compared to the current residential time of day rate (R-OTOD) to exclude the local facilities cost. This was done in recognition that an EV TOU rate is assumed to be for service to an EV charger that is connected to and associated with a residential customer's whole house service.

Rate design calculations provided in Workpaper EAD-1 are shown in two steps: local distribution facilities costs are first spread across all hours in part A, and then moved in Part B outside of the off-peak hours and into the peak and mid-peak hour volumetric rates, such that off-peak charging would exclude such cost in its pricing. This is intended to signal the need for increased local capacity if the EV is charged during mid peak or peak periods, and therefore reflects the increased costs of that capacity during such times.

For the final design, shown in part B, the peak to off-peak ratio is calculated, and is shown to be greater than the 3:1 ratio recognized in the Commission's guidelines for this docket as they were enumerated in Order No. 26,394.

Under this design, a customer receiving energy service from the Company would see a total peak period volumetric rate (for the distribution, transmission and generation components of service) of 24.4 cents per kWh, and rates of 13.285 cents per kWh and 11.142 cents per kWh for the mid-peak and off-peak periods, respectively. All rates are based on current residential pricing and costs of service.

Workpaper EAD-1

Residential EV TOU Rate Design - Detailed Rate Calculations

Rate Design TOU Periods and Billing Determinants

Peak Period: 2 pm - 7 pm, weekdays excluding holidays
Mid-Peak Period: 7 am - 11 pm, daily, excluding peak period hours
Off-Peak Period: All other hours

kWh Usage for Residential Rate Class			
Peak	Mid-Peak	Off-Peak	Total
549,957,946	1,777,416,681	817,596,207	3,144,970,835
17.5%	56.5%	26.0%	

Marginal Costs[1]

				MC Differentials	
	Peak	Mid-Peak	Off-Peak	Peak to Mid-Peak	Mid-Peak to Off-Peak
	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)
Distribution	0.00483	0.00069	0.00000	0.00414	0.00069
Transmission	0.07569	0.00894	0.00023	0.06675	0.00871
Generation	0.08768	0.04702	0.03499	0.04066	0.01203

Rate Design

A. Initial Revenue Neutral Design (assumes that EV monthly customer charge is $16.5. Facilities Costs included in volumetric pricing across all periods)

	Peak	Mid-Peak	Off-Peak	Rate Design Revenue Target
	($/kWh)	($/kWh)	($/kWh)	
Distribution	0.05400	0.04986	0.04917	$ 158,516,539
Transmission	0.08746	0.02070	0.01199	$ 94,695,072
Generation	0.10294	0.06229	0.05026	$ 208,417,217
Total	0.24440	0.13285	0.11142	

B. Final Proposed Design (assumes that EV monthly customer charge is $16.5. Facilities Costs included in only Peak and Mid-Peak volumetric pricing)

	Peak	Mid-Peak	Off-Peak	Rate Design Revenue Target	Peak/ Off-peak ratio
	($/kWh)	($/kWh)	($/kWh)		
Distribution	0.06402	0.05988	0.02065	$ 158,516,539	3.10
Transmission	0.08746	0.02070	0.01199	$ 94,695,072	7.29
Generation	0.10294	0.06229	0.05026	$ 208,417,217	2.05
Total	0.25442	0.14287	0.08290		3.07

Notes

[1] Developed pursuant to marginal costs of distribution, transmission and energy supply developed using methodologies discussed in Marginal Cost Analysis Supporting the Design of PSNH's EV TOD Rate, accompanying this workpaper.

Marginal Cost Analysis Supporting the Design of PSNH's EV TOU Rate

Summary of Approach

Prepared by Amparo Nieto
June 22, 2021

I. Introduction

Eversource has developed a residential Time of Use (TOU) Electric Vehicle Rate (Rate R-EV) proposal in response to the Commission's Order in DE 20-170. The proposed rate is revenue-neutral to the residential Rate R, such that the EV rate would recover the full revenue target assuming the residential average customer load profile. [1]

A fundamental step in the rate design was identifying the marginal costs associated with procurement and delivery of electricity by time of day. The EV TOU rate intends to signal the EV owner the hours when charging the EV will impose the lowest costs to the utility, therefore it is important to estimate the hourly marginal costs of generation, transmission and distribution associated with serving incremental electricity.

Marginal costs were analyzed jointly for purposes of determining the appropriate TOU periods, keeping in mind the Commission's requirement of determining a peak period no longer than five hours. The Company's preference is to keep the TOU periods constant year-round, while adjusting the prices on a seasonal basis as the underlying costs change. Thus, the TOU periods were selected using year-round averages of hourly marginal costs. The TOU period analysis determined that three TOU periods, defined herein, for pricing EV loads would be appropriate, as explained in section II-D.

This document summarizes the main aspects of the marginal cost calculation approach, and the pattern of corresponding hourly costs that was evaluated in the development of the proposed EV rate. The marginal cost calculation by TOU period is only the first step in rate design. It requires an adjustment to meet the class revenue target, keeping in mind marginal costs price differentials by period, as discussed in the narrative and shown in the work paper provided in this supplemental filing.

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[1] Amparo Nieto, currently Senior Director of Energy and Environmental Economics, led the development of marginal costs and time of use period analysis for the design of the EV rate. She has worked with the Company in applying the marginal costs for the development of the proposed residential EV rate.

II. Marginal Costs Calculation

A. Generation

The Company procures supply service from wholesale energy providers via a contract per-kWh price that varies by month and is not differentiated by time of day. The supplier's monthly contract price, stated in flat dollars per kWh, includes the cost of ISO-NE capacity, energy, and ancillary services, assessed to load serving entities as they are required to meet the needs of the Company's Energy Service customers. Eversource converts the supplier's monthly contract price into a seasonal (six-month) average energy supply rate for inclusion in retail rates.[2]

In order to time differentiate the six-month average retail price calculated by the Company for the proposed residential EV TOU rate design, the analysis starts by looking at the underlying costs that suppliers face when determining their supply bids for energy and capacity. These include the following:

a) Day-ahead ISO-NE hourly Locational Marginal Prices (LMPs);
b) ISO-NE Forward Capacity Market (FCM) capacity price ($/kW-mo.) for the planning delivery year;
c) Marginal losses to bring power to customer's premises.

Eversource's wholesale suppliers are responsible for a capacity obligation to ISO-NE. The monthly supplier contract price includes this cost. For purposes of estimating the marginal capacity cost basis for the residential class, the analysis used 2021/22 ISO-NE's FCM price, stated as a $-kW-year. Allocating the annual capacity price to hours requires identifying the hours that are most likely to determine the Company's capacity obligation. Eversource's ICAP tag looks at the coincidence of the Company's loads with region-wide hourly peak. Thus, the Company undertook a probability of peak analysis using the ISO-NE's hourly loads measured at the ISO-NE pool transmission facilities (PTF) node, during the three-year period of 2017-2019. ISO-NE also applies a scaling factor when determining Eversource's residential capacity obligation. The FCM cost was adjusted by ISO-NE's planning reserve margin[3], and by delivery losses to state it as a cost of service provided at secondary voltage.

Similarly, a marginal energy cost calculation by time of day was used. The recent historical variation in hourly LMPs, measured at the NH zone, for years 2017-2019, was assumed to be

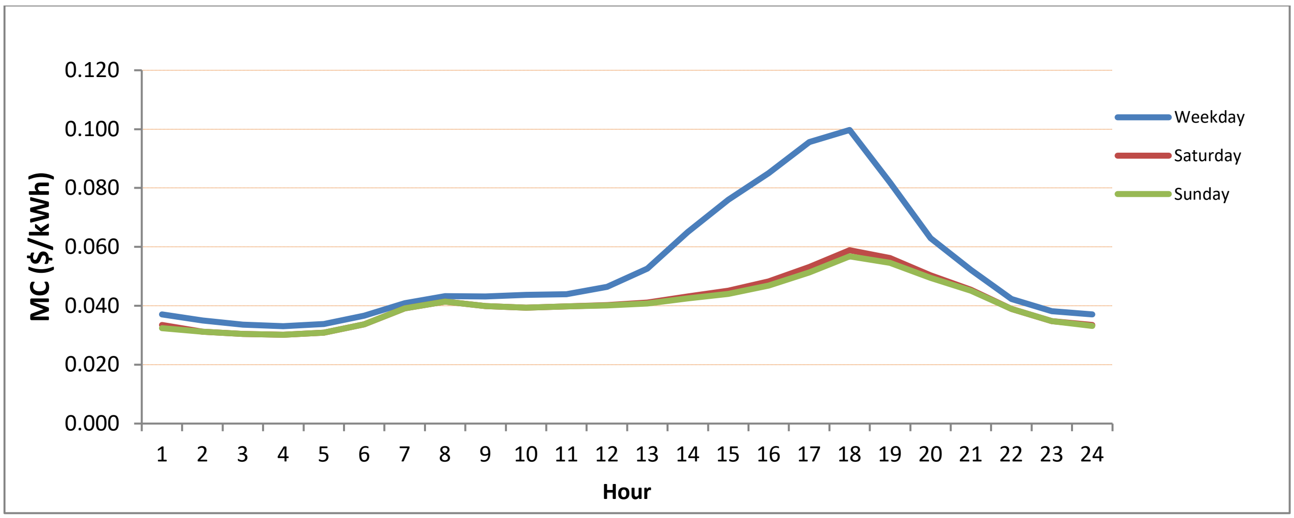
[2] Eversource calculation of the energy supply rate also involves adding the cost of Renewable Portfolio Standard (RPS), as well as energy and RPS reconciliation factors, A&G and working capital expenses.

[3] The current ISO-NE reserve margin of 17.8% was used as a proxy for the scaling factor.

representative of the hourly variation that would be expected for energy supply prices in 2021.[4] The pattern of hourly variation was applied to the estimated energy cost component in the monthly contract price.

The marginal generation capacity costs are concentrated in the summer months. As discussed above, the Company wishes to keep the period definitions non-seasonal in the current EV TOU rate proposal. As a result, the Company defined the appropriate periods by looking at the annual averages of marginal cost. The highest marginal generation costs in ISO-NE occur between 1 p.m. and 7 p.m. All hours reflect Eastern Prevailing Time (EPT). Figure 1 below demonstrates the pattern of total hourly marginal generation costs including energy, generation capacity and operating reserves, for each day type (weekday vs. weekend/holiday).

Figure 1. Year-round Marginal Generation Cost Profile by Day type



B. Transmission Marginal Costs

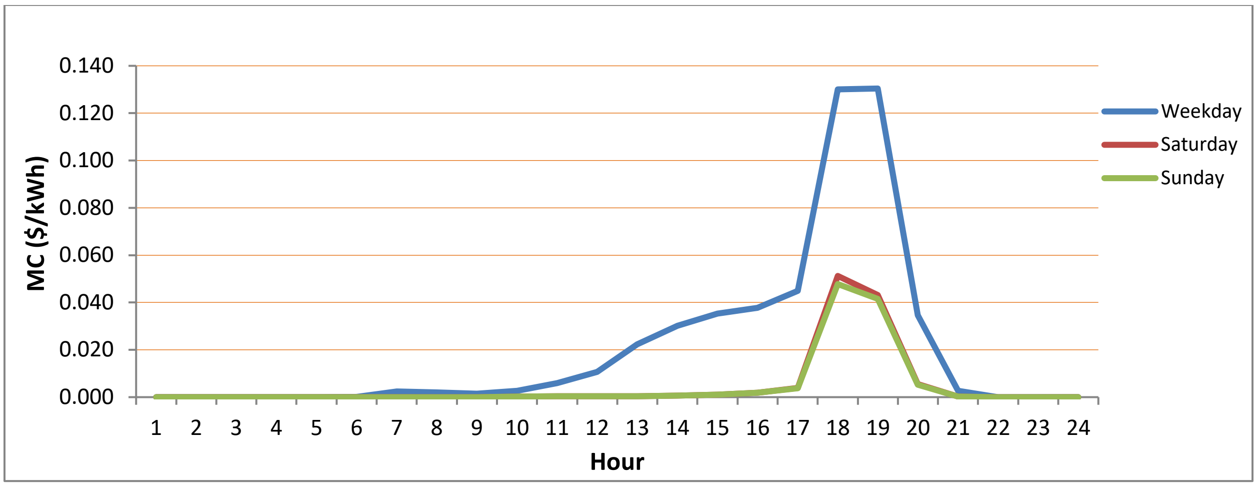
The time-differentiated marginal transmission cost analysis was based on Eversource's current ISO-NE monthly Regional Network Service (RNS) rate, stated in $/kW-year. This represents the financial marginal cost to Eversource, since a customer's load increase at the time of the monthly peak triggers a higher transmission bill (a higher transmission obligation for the Company). The timing of this component of marginal cost required looking at the Company's loads that are

[4] The estimated monthly average generation capacity per-kWh price as well as the average operating reserve price (currently at $0.00748/kWh), were subtracted from the supplier's monthly per-kWh contract price for the period 2021. The residual contract price represents the month's average wholesale energy price.

coincident with the transmission system peak.[5] The monthly RNS rate, measured at the secondary service level by applying the corresponding distribution losses, was allocated to each hour of the month, separately by day type (weekday and weekend), based on the probability that each hour will be that month's peak hour in the transmission system. This probabilistic analysis used five years of transmission-level hourly loads (including wholesale loads), from January 2015 through December 2019.

Figure 2 below shows the pattern of hourly marginal transmission costs, year-round. The marginal transmission costs (RNS rate) is concentrated in the period between 2 p.m. and 7 p.m. on weekdays, with a particularly narrow peak in the late afternoon. This profile reflects the fact that the probability of peak analysis is computed within the month.

Figure 2. Year-round Hourly Transmission Marginal Cost



C. Marginal Distribution Cost

During the course of the Company's 2019/20 rate case, Eversource commissioned a marginal electricity distribution cost study (MCS)[6] to provide support during the rate design step. The 2019 MCS study produced estimates of monthly marginal customer costs (including meter and service drop, customer expenses) by customer class, monthly marginal local distribution

[5] In this analysis Eversource is effectively considered a network customer, with a transmission obligation. This analysis is distinctly different from a resource-based marginal transmission cost analysis that would require identifying the planned growth-related transmission investments in the region and the hours in the year triggering that investment.

[6] Direct Testimony of Amparo Nieto filed before the New Hampshire Public Utilities Commission, "*Eversource Energy Marginal Distribution Cost of Service Study and Implications for Rate Design*" May 28, 2019. Docket DE 19-057.

facilities costs (transformers, primary and secondary conductors) by customer class, and distribution substation costs. The marginal facilities cost (i.e., the local distribution costs) for the average residential customer was estimated at $16.96 per month; this component of marginal cost is driven by changes in the annual customer maximum demand that the planners need to consider when sizing the local transformer and conductors.

The calculation of marginal distribution substation costs involved an in-depth review of the Company's budgeted investments for the upcoming five-year planning period (2020-2024), along with a review of the distribution station peak load forecast. Separate station cost estimates were developed for:

- Bulk stations that are fed from the transmission system (115kV) and typically convert power to 34 kV or directly to 12 kV;
- Distribution (non-bulk) substations that convert the load coming from the bulk station to either 12 kV or 4 kV.

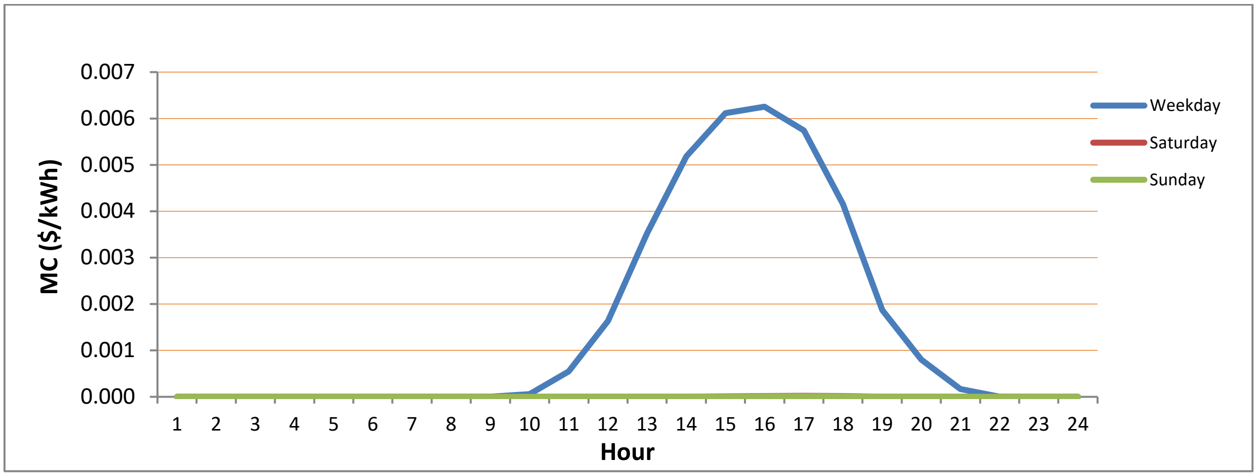
To determine marginal costs, the identified peak-load related station investments were divided by the project's expected added capacity. In the case of bulk stations, the marginal investment per kW of added capacity was adjusted by current planning reliability standard, to estimate costs in dollars per-kW of added peak load. The study developed annualized marginal costs by applying the corresponding economic carrying charge, adding marginal O&M expenses and A&G and general plant loading factors.

The study estimated marginal cost for the capacity-expanding areas, as well as a system-wide average. Only a small share of the service territory (about 20 percent) was identified as having plans to expand capacity for load-growth reasons, and therefore only in those areas peak load reduction would produce distribution cost savings by deferring investment in the five-year planning cycle.

For purposes of using the 2019 marginal cost estimates for the design of the EV TOU rate, a two percent annual inflation factor was applied to restate them in 2021 dollars, resulting in an annual value of $5.74 per kW-year. The next step in the 2019 MCS study was to allocate the sum of annualized marginal bulk and non-bulk distribution station costs to hours, in order to support the development of a TOU distribution rate. The allocation of the annualized distribution cost to hours was based on a distribution peak analysis that calculates each hour's expected probability of being the annual peak at the distribution substation level, using four years of hourly load data at Eversource's bulk substations (from 2015 through 2018).

The probability of peak analysis determined that the loads occurring in hours noon to 7 p.m. in the summer – particularly July and August – are the primary drivers of the capacity growth-related expansion at the upstream primary level. Regression analysis determined that when using three TOU periods on an annual average basis (i.e., no seasonality), a peak period of seven hours on weekdays (noon to 7 p.m.) would provide the highest goodness of fit from a distribution cost-only basis. This suggests that if the TOU analysis only considered variation in the distribution loads, a seven-hour peak period would be more appropriate to capture the relative variation in distribution cost profile. Figure 3 shows the year-round hourly profile of marginal distribution costs for a secondary voltage level of service, stated in 2021 dollars.

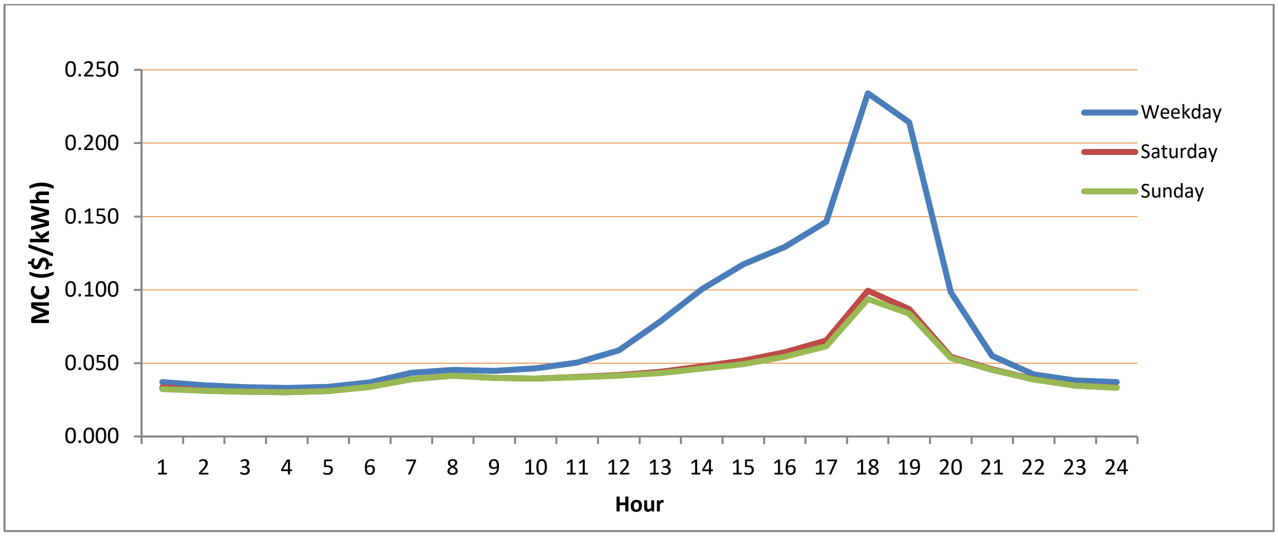
Figure 3. Year-round Hourly Marginal Upstream Distribution Costs



D. Total Hourly Marginal Cost Profile and TOU periods

The definition of TOU periods considered the profile of total costs of service as opposed to only distribution costs. In order to signal the hours of lowest and highest overall *supply* and *delivery* cost, the hourly generation, transmission and distribution marginal costs were added together, and the overall pattern was analyzed to be useful for the year-round EV TOU rate. Figure 4 shows the total hourly profile averaged across all months for each hour of the day, separately from weekday and weekends.

Figure 4. Year-round Total Marginal Costs, Weekday by MC Category



The resulting pattern of hourly costs supports realigning the existing time of day (TOD) distribution rate periods to be more reflective of Eversource's year-round peak and off-peak costs of meeting incremental load in any given hour. A preliminary observation from data visualization suggested that the lowest marginal cost of service, including all cost components, occurs during overnight hours until 7 a.m., followed by a slightly higher increase in cost until about 1 p.m. A regression analysis showed that a six peak-hour period beginning at 1 p.m. and ending at 7 p.m. would be cost reflective. Adopting a shorter, five-hour peak period as recommended by the Commission, reduces the price signal regarding the impact of a load increase (or reduction) from the hour of 1 p.m. to 2 p.m. A five-hour peak period is nevertheless reasonable in terms of signaling total highest marginal cost of service.