Documentation of the Retail Price Model

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1. Introduction

The Retail Price Model (RPM) provides a first-order estimate of average retail electricity prices using information from the EPA's Power Sector Modeling Platform v6 using the Integrated Planning Model (IPM) and the EIA's Annual Energy Outlook (AEO). This model was developed by ICF at the direction of EPA.

This document provides an overview of the model and documents the model calculations, inputs, and outputs.

2. Background

IPM is a wholesale power market model that projects wholesale prices paid to generators. Electricity consumers—industrial, commercial, and residential customers—face a retail price for electricity that is higher than the wholesale price because it includes the cost of wholesale power and the costs of transmitting and distributing electricity to end-use consumers. The RPM was developed to estimate retail prices of electricity based on outputs of EPA's Base Case using IPM and a range of other assumptions, including the method of regulation and price-setting in each state.

Traditionally, cost-of-service (COS) or Rate-of-Return regulation sets rates based on the estimated average costs of providing electricity to customers plus a "fair and equitable return" to the utility's investors. States that impose cost-of-service regulation typically have one or more investor owned utilities (IOUs), which own and operate their own generation, transmission, and distribution assets. They are also the retail service provider for their franchised service territory. IOUs can also buy power from neighboring IOUs or organized markets but do so only to secure incremental power that is less expensive than power generated by their own assets. Under this regulatory structure, retail power prices are based on average historical costs and are established for each class of service by state regulators during periodic rate case proceedings.

During the 1990s, certain states began to deregulate their retail electricity market. In most deregulated states, vertically integrated utilities sold off their generating assets and became distributors of power. Under the retail choice programs implemented as part of deregulation, individual retail customers could choose their electricity supplier while still receiving delivery over the power lines of the electric utility. These deregulated electricity markets are designed to reflect the marginal costs of generating and delivering power in a competitive marketplace. Retail service providers secure necessary power supplies through a combination of long-term contracts and purchased power in the wholesale spot market. Wholesale power pricing is based on the marginal costs of generating power and the costs of transporting that power to load centers.

The restructuring[1] of the electric power industry in the U.S. historically fell under the jurisdiction of both federal and state authorities. Due to states' differing choices in regulatory process, the extent and nature of power market deregulation varies widely across the U.S. As a result, differences in regional power market structures impact how electric retail prices are set in those markets. Regional power markets can be generally grouped into three broad categories: deregulated/competitive, regulated/COS, and a combination of those two structures.

The RPM accounts for this diversity of regulated and deregulated market structures in U.S. by calculating both competitive and cost-of-service retail prices for each region and later allocating and weighting those two prices to individual IPM regions according to the market structure(s) determined as the most representative regulatory model for each region.

[1] The restructuring process started in 1978 with passage of Public Utilities Regulatory Policy Act (PURPA), which required utilities to purchase power from qualifying facilities at the utilities avoided cost. Following PURPA, Energy Policy Act of 1992 among other provisions, allowed for creation of independent power producers. In 1996, FERC Order 888 addressed the inadequacies of transmission access and pricing.

3. The Retail Price Model

The retail price of electricity to customers is comprised of generation, transmission, and distribution components.

The RPM incorporates two price models to capture both deregulated markets with competitive pricing and regulated markets with cost-of-service pricing. In both models, transmission and distribution (T&D) costs are assumed to remain regulated and the related price component is based on the average costs to build, operate, and maintain these systems. These models use generation-related outputs from an IPM-modeled scenario together with T&D and other cost projections and assumptions from EIA's AEO Reference Case to estimate the retail price of electricity. The two models are:

- The **Competitive Price Model**, which estimates prices based on wholesale power prices, transmission and distribution costs, and applicable taxes.
- The **Cost-of-Service (COS) Model**, which estimates prices based on average cost to generate power and includes regulated returns to utilities, taxes, and transmission and distribution costs.

While deregulation is implemented at the state level, individual IPM model regions can include multiple states. The share of each IPM region that is subject to deregulated/cost-of-service ratemaking is based on EIA's AEO 2018 and other research. All IPM regions that are individually mapped to a NEMS region get the same deregulation share as the corresponding NEMS region. In multi-state IPM regions, the regional retail price is a function of the average degree of deregulation across the included states. Attachment 1 presents the characterization of retail price regulation assumed for each IPM region. The calculation is shown in Equation 1. For example, if the competitive market price of the ERC_REST region is calculated to be $40/MWh while the COS price is calculated to be $80/MWh, and the deregulation share is 88% while the COS share is 12%, the retail price in ERC_REST is calculated as $40/MWh × 88% + $80/MWh × 12% = $44.8/MWh.

Equation 1 Regional Average Retail Price

Regional Average Retail Price (mills/kWh) *= Competitive Retail Power Price * Deregulation Share (%) + Cost-of-Service Retail Power Price * Cost-of-Service Share (%)*

The rest of this document explains how retail prices are calculated under the competitive and cost-of-service models, and how the RPM estimates an average retail price for IPM regions that include both competitive and cost-of-service states.

3.1. Competitive Retail Power Price Model

Figure 1 summarizes the structure of the model that calculates competitive retail power prices for those deregulated regions noted in Attachment 1 and for those portions of the regions with mixed retail market structures. All the inputs to the model either come from an IPM-modeled scenario or an AEO Reference Case.

Competitive retail power prices comprise three components: competitive generation cost, transmission charge, and distribution charge. Equation 2 illustrates the formula for calculating the competitive retail power price.

Equation 2 Competitive Retail Power Price

Competitive Retail Power Price (mills/kWh) *= (Competitive Generation Cost + Transmission Charge + Distribution Charge)*

<u>Competitive generation costs</u> (in mills/kWh) are calculated as a summation of the marginal cost of electricity generation per kilowatt-hour of sales, the cost of maintaining adequate generating capacity to meet reserve margins over and above the peak load embedded in each kilowatt-hour of sales, and the

cost of renewable energy credits (REC) associated with the compliance of Renewable Portfolio Standard (RPS) per kilowatt-hour of sales.[2] See Equation 3.

Transmission charges (in mills/kWh) and distribution charges (in mills/kWh) for use in Equation 2 are taken from EIA's AEO 2018 Reference Case at a NEMS region level and mapped to the appropriate IPM region. These charges reflect the cost of operating transmission and distribution infrastructure to move power from generators to retail end-use consumers in each region. Unlike the generation costs, which are based on IPM projections, transmission and distribution charges do not change across modeled IPM scenarios.

Equation 3 Competitive Generation Cost

Competitive Generation Cost (mills/kWh) *= (Marginal Energy Cost + Reliability Cost + REC Cost) * (1 + Tax Rate)*

The three costs illustrated in Equation 3 have the following key components:

The marginal energy cost (in mills/kWh), is a direct output of IPM for each region. This represents an energy-weighted average annual price of power (total cost divided by total generation). See Equation 4.

The reliability cost (in mills/kWh) is the product of the capacity price (in $/kW-year), a direct output of IPM for each region, and the region's reserve requirement[3] (kW), which is then distributed evenly across total sales. A capacity price is typically expressed as an annual payment for each kilowatt kept in service. Retail ratepayers do not face the capacity price directly; instead, the capacity price determines the total annual reliability cost, which is then spread out over total sales such that a fraction of the total reliability cost is recovered with each kilowatt-hour sold. This is the cost of ensuring that adequate capacity is available to meet peak loads plus a reserve margin determined by electric reliability authorities in each region.[4]

The REC cost (in mills/kWh) is the product of the endogenously-calculated REC Price (mills/kWh) and the proportion of total sales represented by renewables that comply with state renewable portfolio standard (RPS) policy requirements. The REC cost reflects the cost premium for generating electricity from renewable resources relative to the market price of conventionally generated electricity. This cost is incremental to the marginal energy cost and reliability cost, as this is incurred only in markets with renewable portfolio standards and the REC price is only earned by the technologies that are compliant with each RPS.

A tax rate representing state and local taxes is then applied to the sum of these three price components. Tax rates at the NEMS region level were obtained from EIA's AEO 2018.

Equation 4 Marginal Energy Cost and Reliability Cost

Marginal Energy Cost and Reliability Cost (mills/kWh) *= [Marginal Energy Price (mills/kWh) + (Capacity Price ($/kW-year) × (1 + Reserve Margin)) / (8.76 × Load Factor))] / (1 – Distribution Loss Factor %)*

The distribution loss factor accounts for power losses that occur as the power moves through the transmission and the distribution grid.[5] The marginal energy cost and reliability cost equation

[2] A Renewable Portfolio Standard (RPS) is a regulatory requirement that utilities meet a specified percentage of their power supply using qualified renewable resources.

[3] A region's reserve requirement is a function of its peak load and reserve margin.

[4] See Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, available at: https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm

[5] The voltage levels in the transmission network are higher than those in the distribution network. Lower voltages in the distribution network result in higher losses relative to the transmission network.

incorporates the distribution loss factor so that retail rates estimated by the model reflect rates of total electricity generated, rather than just the electricity delivered. The distribution loss factors in RPM are calculated as the ratio of the NEMS region level electricity sales and net-energy-for-load projections from the AEO 2018. The NEMS region level estimates are mapped to IPM model regions.

3.2. Cost-of-Service (Regulated) Retail Power Price Model

The second module of the RPM calculates a cost-of-service electricity price based on historical average costs for those regions.

Figure 2 summarizes the methodology for developing prices on a cost-of-service basis. In addition to the cost of generation, as in the competitive price calculation, the cost-of-service price to customers also includes the recovery of costs associated with T&D facilities and services. Given the assumption that T&D charges are regulated, these charges are identical in the competitive and the cost-of-service models. Equation 5 illustrates the formula for calculating the cost-of-service retail power price.

Equation 5 Cost-of-Service Retail Power Price

Cost-of-Service Retail Power Price *= (Final Cost of Power Generation + Transmission Charge + Distribution Charge)*

The final cost of power generation in Equation 5 is comprised of the following expenses and includes the cost of meeting all power market operational requirements such as meeting electricity demand, meeting reserve margin requirements and complying with environmental regulations:

The regional Average Generation Cost per kWh Sold (mills/kWh) is the sum of total costs for generation divided by total sales[6] in each region. The total generation costs include fuel costs, variable operation and maintenance (VOM) costs, fixed operation and maintenance (FOM) costs, annualized capital costs for new units and retrofits, CO_2 transportation and storage costs, wholesale power costs for interregional transactions, and the net cost of interregional REC transactions in each region. Additionally, it is possible to incorporate allowance costs related to environmental policies by adding to the total generation cost. These are all projected outputs of IPM.

Utility Depreciation Costs (in mills/kWh) represent the ability of regulated generators to recover the costs of depreciated capital. These costs are obtained directly from EIA's AEO 2018. All IPM regions that are individually mapped to a NEMS region get the same NEMS region level utility depreciation cost.

In COS regions, utilities are allowed by regulators to earn a return on their rate base. The rate of return is regulated regionally and is reflected in this model as Return to Equity and Debt (in mills/kWh). These charges are obtained directly from the AEO 2018. All IPM regions that are individually mapped to a NEMS region get the same Return to Equity and Debt as the corresponding NEMS region.

The capital costs of existing units constructed prior to 2016 are not explicitly modeled in IPM. The utility depreciation costs noted above capture capital cost recovery of such units built by regulated utilities.

[6] The total sales in each region are calculated as the product between net-energy-for-load and the distribution loss factor.

Since the capital costs of non-utility generators (NUG) constructed prior to 2016 are not accounted for in model results or in the utility depreciation costs, we add an estimated NUG Adder (in mills/kWh) to account for the capital costs that are passed through to ratepayers in the retail rate. This adder is based on EIA's AEO 2018.

Generation is subject to state and local taxes, and these taxes are generally passed through to ratepayers in the COS retail rate. Therefore, we add a regional Tax Rate (in mills/kWh) to the retail power price in COS regions. This rate is estimated regionally by summing the total regional tax dollars and dividing by the sum of fuel, O&M, wholesale, NUG, depreciation, and return costs as summarized by EIA's AEO 2018.

Equation 6 summarizes the calculation for calculating the Final Cost of Power Generation.

Equation 6 Final Cost of Power Generation

Final Cost of Power Generation (mills/kWh) *= (Average Generation Cost per kWh Sold + Utility Depreciation Costs + Return to Equity and Debt + NUG Adder) × (1+Tax Rate)*

4. Caveats

The RPM discussed in this memo is a first-order approach for estimating the retail price of electricity based on IPM-projected outputs as implemented in EPA's Power Sector Modeling Platform v6. This model makes several assumptions to simplify the data gathering and price estimation process. These assumptions include the use of EIA's AEO 2018 as the primary source for non-IPM related RPM inputs and then if those inputs remain constant across IPM model runs, even for modeling scenarios in which electricity demand is no longer assumed to be consistent with the AEO 2018 reference case. For example, a modeling scenario assuming increased energy efficiency would yield lower electricity consumption over which fixed costs for T&D could be recovered via the T&D charge in mills/kWh. If fixed costs for T&D are assumed to persist at the same level in the future regardless of increased energy efficiency, the T&D charge could be expected to increase beyond the assumed charge taken from the AEO 2018 reference case.

However, a review of projected T&D rates from the AEO 2013 reference case and two scenarios with different levels of electricity demand reduction shows that the projected impact of change in demand on the T&D component of retail rates is relatively small. Table 1 summarizes the 2020 and 2030 projected transmissions and distribution rates from the AEO 2013 reference case, the high demand technology case, and the best available demand technology case. These cases represent a 6% to 16% reduction in demand, relative to the reference case, over the 2020-2030 time horizon.

Table 1 Projected Prices by Service Category (2011 cents per kilowatt-hour)

	2020			2030		
	Generation	**Transmission**	**Distribution**	**Generation**	**Transmission**	**Distribution**
Reference	5.6	1.1	2.8	6.0	1.1	2.6
High technology	5.4	1.1	2.9	5.7	1.1	2.7
Best available technology	5.3	1.1	2.9	5.4	1.1	2.7

Source: AEO 2013

Attachment 1 Assumptions Regarding State of Retail Rate Regulation for IPM Regions

State of Retail Regulation	IPM Region	NEMS Region	Deregulation Share (%)	Cost-of-Service Share (%)
Full Deregulation with Competitive Pricing	NY_Z_C&E	NYUP (8)	100%	0%
	NY_Z_F	NYUP (8)	100%	0%

State of Retail Regulation	IPM Region	NEMS Region	Deregulation Share (%)	Cost-of-Service Share (%)
	NY_Z_G-I	NYUP (8)	100%	0%
	NY_Z_J	NYCW (6)	100%	0%
	NY_Z_K	NYLI (7)	100%	0%
	NY_Z_A	NYUP (8)	100%	0%
	NY_Z_B	NYUP (8)	100%	0%
	NY_Z_D	NYUP (8)	100%	0%
	PJM_WMAC	RFCE (9)	100%	0%
	PJM_EMAC	RFCE (9)	100%	0%
	PJM_SMAC	RFCE (9)	100%	0%
	PJM_PENE	RFCE (9)	100%	0%
Full Regulation with Costs of Service Pricing	FRCC	FRCC (2)	0%	100%
	MIS_WOTA	SRDA (12)	0%	100%
	MIS_AMSO	SRDA (12)	0%	100%
	MIS_AR	SRDA (12)	0%	100%
	MIS_D_MS	SRDA (12)	0%	100%
	MIS_LA	SPSO (18)	0%	100%
	PJM_Dom	SRVC (16)	0%	100%
	S_VACA	SRVC (16)	0%	100%
	S_C_KY	SRCE (15)	0%	100%
	S_D_AECI	SRDA (12)	0%	100%
	S_C_TVA	SRCE (15)	0%	100%
	S_SOU	SRSE (14)	0%	100%
	SPP_N	SPNO (17)	0%	100%
	SPP_WEST	SPSO (18)	0%	100%
	SPP_SPS	SPSO (18)	0%	100%
	WECC_CO	RMPA (22)	0%	100%
Mix of Competitive and Cost-of-Service pricing	ERC_REST	ERCT (1)	88%	12%
	ERC_WEST	ERCT (1)	88%	12%
	ERC_PHDL	ERCT (1)	88%	12%
	MIS_MAPP	MROW (4)	1%	99%
	MIS_IL	SRGW (13)	9%	91%
	MIS_INKY	RFCW (11)	59%	41%
	MIS_IA	MROW (4)	1%	99%
	MIS_MIDA	MROW (4)	1%	99%
	MIS_LMI	RFCM (10)	10%	90%
	MIS_MO	SRGW (13)	9%	91%
	MIS_WUMS	RFCW (11)	59%	41%
	MIS_MNWI	MROW (4)	1%	99%
	NENG_CT	NEWE (5)	95%	5%
	NENGREST	NEWE (5)	95%	5%
	NENG_ME	NEWE (5)	95%	5%
	PJM_West	RFCW (11)	59%	41%
	PJM_AP	RFCW (11)	59%	41%
	PJM_COMD	RFCW (11)	59%	41%
	PJM_ATSI	RFCW (11)	59%	41%
	SPP_NEBR	MROW (4)	1%	99%
	SPP_WAUE	MROW (4)	1%	99%
	WEC_CALN	CAMX (20)	10%	90%
	WEC_LADW	CAMX (20)	10%	90%
	WEC_SDGE	CAMX (20)	10%	90%
	WECC_SCE	CAMX (20)	10%	90%
	WECC_MT	NWPP (21)	3%	97%
	WEC_BANC	CAMX (20)	10%	90%
	WECC_ID	NWPP (21)	3%	97%
	WECC_NNV	NWPP (21)	3%	97%

State of Retail Regulation	IPM Region	NEMS Region	Deregulation Share (%)	Cost-of-Service Share (%)
	WECC_SNV	AZNM (19)	2%	98%
	WECC_UT	NWPP (21)	3%	97%
	WECC_PNW	NWPP (21)	3%	97%
	WECC_WY	NWPP (21)	3%	97%
	WECC_AZ	AZNM (19)	2%	98%
	WECC_NM	AZNM (19)	2%	98%
	WECC_IID	AZNM (19)	2%	98%

Figure 1 Summary of Competitive Retail Price Estimates at the Regional Level

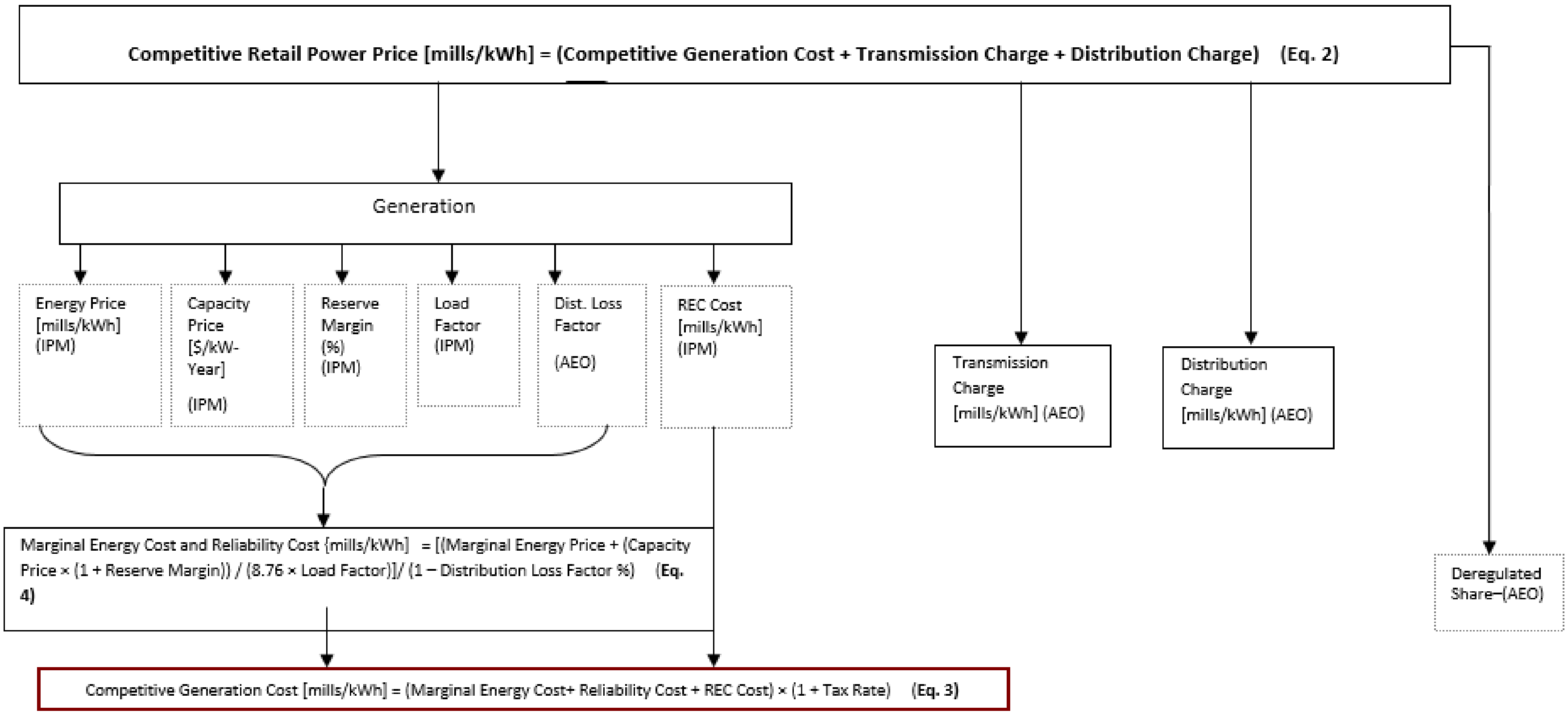

Figure 2 Summary of Cost-of-Service Retail Price Estimates at the Regional Level