

*BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION*

A GUIDE TO UTILITY RATEMAKING



*BY JAMES H. CAWLEY
AND NORMAN J. KENNARD
(2018 EDITION)*

New Foreword

The Pennsylvania Public Utility Commission, as an organization of professionals, stands on the shoulders of the commissioners and staff that went before. Our predecessors' policy issues and economic challenges were different, but the solutions they shaped are the foundation that subsequent generations have built upon to solve their own.

The original 1983 Rate Case Handbook was still in active use well past any probable expiration date, largely because the fundamental principles of base ratemaking remained unchanged. "It's very helpful, except that none of what has occurred in the last 35 years is included" was the familiar grievance. Hopefully, this rewrite fills in those gaps and ages with equal grace.

Since Jim Cawley and I authored this book, with a lot of help, 35 years ago, the world has transformed profoundly. The original handbook was typed on an IBM Selectric or similar typewriter that possessed very, very limited memory. When the seemingly endless rounds of revisions were complete, the typist was the most relieved of all. In comparison, this version is being written on a Dell OptiPlex 7050 with 238 GB hard drive, 4 GB of RAM, and a 3.4 GHz processor. It has sophisticated software that can "link" to a mysterious hole in the universe called the "internet."¹ The document has been atmospherically shared and edited among its multiple contributors in "the cloud."

In 1983, voice telephone service was all there was to know about telecommunications. Although the telecommunications industry was becoming selectively competitive, notably in long-distance calling plans, AT&T was broken up only later by the U.S. Department of Justice's antitrust law suit. Natural gas was in short supply with the process of deregulating wellhead prices only having begun in 1978 with the Natural Gas Policy Act. Commodity prices were still very high (in 1983 dollars especially). Gas companies retailed the gas itself, as well as performed the transport and delivery functions. Customers' ability to purchase directly from the gas producer was limited to only the largest users and subject to tight limitations. The electric industry was also vertically integrated as a monopoly. The generation side of the house was

¹ The links appearing in this handbook were accessed during September through November 2017. Most likely, they will change over time and may appear "broken" when clicked on at some point in the future. As this forward acknowledges; all things change.

under great financial stress, struggling to build 1,000 Mw nuclear generating facilities with large cost overruns. The 1979 accident at Three Mile Island was still recent. There were no solar or wind resources.

Economic circumstances were very dissimilar as well. Inflation had peaked at 13.5 percent three years earlier in 1980 but was still very high in 1983. The 10-year treasury yield exceeded 10 percent, reaching an apex of almost 12 percent in 1985. The nation's highest ever annual unemployment rate of 9.7 percent had been recorded in the prior year. Electric and natural gas demand was tanking, stranding a great deal of capacity in the pipelines and wires of the utilities. The country as a whole and Pennsylvania, in particular, were experiencing a severe economic recession that officially started in 1980. The term "rust belt" came to describe the then-unfolding, sorry decline in large-scale American manufacturing.

Today, in many ways, things are better. Inflation, unemployment, and the cost of money are all very low.² The Marcellus Shale natural gas play, centered in Pennsylvania, has revolutionized the world energy landscape. Commodity prices are lower now, even nominally, than they were in 1983, and supply is abundant.³ The electric utility industry in Pennsylvania is metamorphosing from a centralized generation-and-transmission operation into a diversified mix of traditional and distributed generation operating in a competitive environment with the controls created by smart meters and smart grids. The focus of telecommunication has shifted to focus on something we could hardly imagine—the internet. The monopoly market of Ma Bell has been invaded by cable, cellular, and satellite providers. Texting, not the phone call, is the generationally-preferred means of interpersonal communications.

These developments are almost all good. When viewed from the perspective of a 1983 younger self, they become truly remarkable. But now we worry about cyber-attacks.

As was true of the original handbook, many individuals contributed. First, a special thank you to Chairman Gladys Brown for supporting this project and to Director Rick Kanaskie for broaching the idea of a handbook rewrite, providing refuge as it was being authored and donating BI&E's considerable collective expertise. The book owes much indebtedness to the very substantial revisions and suggestions of Rachel Maurer, Allison Kaster, Lisa Gumby, Christine

² Inflation is subdued 1.3 percent (2016). Current unemployment is 4.8 percent. The current 10-year treasury yield is 2.26 percent.

³ The nominal delivered price of natural gas has increased, but in real dollars has remained constant.

Wilson, Joe Kubas, Jeremy Hubert, Rich Layton, Matt Stewart, Dave Washko, Sean Donnelly, Derek Vogelsong and Dan Mumford. Also, thanks to TUS Director Paul Diskin, Chief Administrative Law Judge Charles Rainey, and Secretary Rosemary Chiavetta for their contributions.

And finally, a wistful and heartfelt acknowledgement to those who have gone before.

Norman J. Kennard, Commissioner
Harrisburg, February 2018

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James H. Cawley (*above right*) served two terms as a member of the Pennsylvania Public Utility Commission (PUC), from 1979 to 1985 and from 2005 to 2015, the second longest combined tenure in the Commission's (and its predecessor, the Public Service Commission's) history dating to 1913. He served as Chairman from 2008 to 2011. After completing his term of office in 2015, he became Of Counsel to Skarlotos Zonarich LLC, a Harrisburg, PA, law firm. A graduate of St. Bonaventure University and Notre Dame Law School, Cawley was one of the original law clerks for Pennsylvania's Commonwealth Court when it came into existence in 1970, served as majority counsel to the state Senate Consumer Affairs Committee and chief counsel to the Democratic floor leader in the Senate, and was a major drafter of the Pennsylvania Public Utility Code. While at the PUC, Cawley was appointed by the Federal Communications Commission to serve as a member of the Federal-State Joint Board for Universal Service.

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I. Introduction

A. Public Utilities

Businesses that provide electric, gas, water, or telephone services have been historically singled out for monopoly status and price regulation and, thereby, treated differently from shoe, paper, and mouthwash companies.

The concept of a public utility developed long ago when it became evident that society had a vital interest in certain essential services and that a free market could not be depended upon to offer the service universally or price it at levels that society could afford. Historically, important key services were subject to public regulation. Grain warehouses, flour mills, ferries, and inns are but a few examples of businesses that were once price-and-service-regulated, owing to their commercial import. Alternatively, price collusion and other forms of trade restraint among a few owners in an otherwise free market are the subject of antitrust laws designed to prevent monopoly.

Modern utility regulation grants monopoly status and represents an agreement between the public and the business enterprise model. In exchange for a generally exclusive, monopolistic market position granted to the utility, society receives the assurance that an essential service will be available, adequately produced to meet demand, provided to all who require it, and priced at a reasonable level. The utility assumes the obligation to serve a defined region; to serve all customers within this area; and to charge only the rates permitted by the government.

1. The Monopoly Franchise

Modern rate regulation of utility services commenced in the early nineteenth century. Regulation of “natural monopolies” swept in with the trust-busting of the early twentieth century, in reaction to the *laissez faire* outcomes of that era.

Previously, essential services regulation was accomplished by state charter and local franchise (the latter still in use for cable TV companies). Natural gas company charters under the Natural Gas Companies Act of 1885 were a typical Pennsylvania statutory arrangement. The fledgling company made a perfunctory filing describing what it wanted to do (produce, transport, or distribute in a region or along its lines). The Secretary of State dutifully granted “letters patent” authorizing operation, and you were in business. Expansion was just as simple. No exclusivity of territory. No rate regulation. No obligation to serve.

This changed in 1913, when the power and authority to regulate the rates and services of utilities was delegated by the legislature to the Public Utility Commission (PUC).⁴ The PUC regulates privately-owned entities, persons, or corporations, owning or operating facilities that provide the following fixed utility services to the public for compensation:

- **Electric distribution** (transmitting, distributing, or furnishing electricity or steam to produce light, heat or power)
- **Gas distribution** (Producing, generating, transmitting, distributing, or furnishing natural or artificial gas and transporting or conveying natural or artificial gas)
- **Water and waste water** (Diverting, developing, pumping, impounding, distributing, or furnishing water. Wastewater collection, treatment or disposal)
- **Landline telephone** (Conveying or transmitting messages or communications)⁵

The Commission does not regulate certain types of organizations that offer these same services, particularly: municipal entities offering services within their municipal limits on the theory that voters have control;⁶ cooperatives, because the customers are members (owners); and municipal authorities as controlled by the municipalities creating them.⁷ Philadelphia Gas Works and the Pittsburgh Water and Sewer Authority are the two exceptions, as the General Assembly has conferred jurisdiction over these entities to the Commission.

Economists have advanced several theories for the existence of price regulation in an otherwise competitive, private enterprise economy:

- **Natural Monopoly**⁸ - Utilities operate at lower unit costs in a monopoly market than they do under competition, chiefly because they achieve decreasing average unit costs as output increases. This occurs because the heavy fixed costs of these industries are distributed more thinly to each unit of output as production rises (i.e., economies of scale). By serving an entire market without competition, utilities can concentrate their production in larger and more efficient plant and equipment, producing services at lower operating expenses and less plant

⁴ Actually, its predecessor, the Public Service Commission, as described subsequently.

⁵ Code § 102 (definition of public utility). The Commission also regulates motor carriers, steam companies, and several other services.

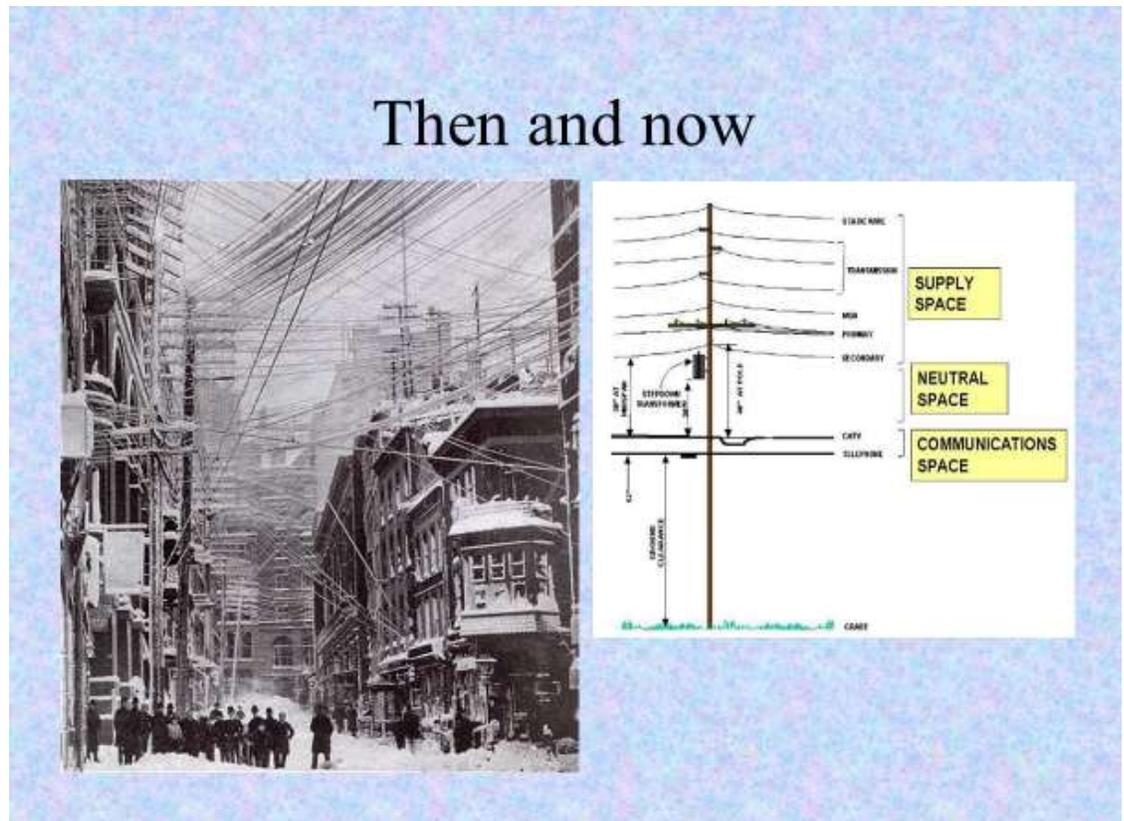
⁶ The PUC does regulate rates for customers served outside the municipal boundary. Code § 1102 requires any municipal corporation seeking to provide public utility service beyond its corporate limits to first obtain a certificate of public convenience from the Commission.

⁷ The Municipal Authorities Act of 1945 declared that the courts of common pleas hold exclusive jurisdiction over the rates and services of authorities. 53 Pa. C.S. § 5607 See, *Calabrese v. Collier Twp. Mun. Auth.*, 240 A.2d 544, 548 (1968); and *Elizabeth Twp. v. Mun. Auth. of McKeesport*, 447 A.2d 245, 246 (1982).

⁸ Natural monopoly is a misnomer. Market structures are imposed by public policy to achieve some end and not by the forces of nature.

investment per unit of output than smaller facilities. Finally, the larger utilities also can realize economies from buying materials in large quantities. The monopoly market structure therefore is efficient.

- **Fixed Capital** - Public utilities are extremely capital-intensive as opposed to labor- or expense-intensive, and the rate of asset turnover (ratio of revenues to assets) is relatively low. For example, a retail company can reasonably expect that gross revenues (before expenses) in any given year will exceed the total assets of the company. On the other hand, utilities' average asset turnover is roughly four years. That is, annual revenues equal only one-fourth of the total investment. Moreover, these large investments are stationary, highly specialized, and not readily sold or converted to cash. It would be difficult to induce investment in such an industry without the assurance of stable revenues provided by monopoly status.
- **Limited Duplication** - Given the capital intensity and long capital turnover of the utility industry, it would be wasteful and uneconomic to have two or more companies running duplicate cables or mains throughout the same town or area.



- **Necessity and Diversity** - Utility services are essential to modern life. Sufficient capacity must be available to meet customers' peak demand, even though the peak may extend for only a few hours per year. Again, the monopoly market structure encourages stability, which assures that this demand will be met. The exclusiveness of a monopoly permits the utility and its customers to benefit from

a wide diversity of customer demand—from residences to small businesses to large factories.

There are other, less theoretic reasons, as well, that plausibly explain the anomaly of monopoly in an otherwise free market system:

- **Market protectionism** - The more conspiratorial theory is that the industries themselves sought regulation to preclude competition.
- **Long-term contracting** - The theory of mutual captivity posits that, in exchange for permanent occupancy of public rights of way, the government sought assurance that rates would be reasonable to constituents and services would be widely provided. Utilities seeking right of way occupancy desired regulation that was fair.

For these reasons, and probably others, state legislatures granted providers of electricity, gas, water and telephone services monopoly status the exclusive right to serve a defined geographic area (franchise).

Along with the conferral of an exemption from competition, utilities must concede several items. Traditional economic theory holds that, unrestrained, a monopolist will do two basic things: raise the price well beyond the actual cost of production; and restrict output in the self-interest of profit maximization. Therefore, legislators placed two basic limitations on such monopolistic behavior:

- **Price Regulation** - To counter the natural tendency of the monopolist to charge the monopoly price, the rate a utility may charge is regulated. No change may be made in the rates charged for service without the express approval of the regulatory commission. Rates are to be set by regulation to recover the cost of providing service, which includes reasonable and necessary operating expenses and taxes, a return of investment in the form of depreciation, and a fair return, or profit, on the investment made to provide the service. As a matter of constitutional law (the Fifth Amendment's last clause), regulators may not set rates so low that they are tantamount to confiscation of property.
- **Service Regulation** - Utilities are under a statutory obligation to serve all applicants located within their franchise area. In general, the regulated monopolist may not cut back output to maximize profit. Utility service must be provided upon demand in the quantities demanded.

2. Operating Characteristics

Before understanding the process of regulating the rates and services of a public utility, one must first understand the industries themselves.

a) Electricity

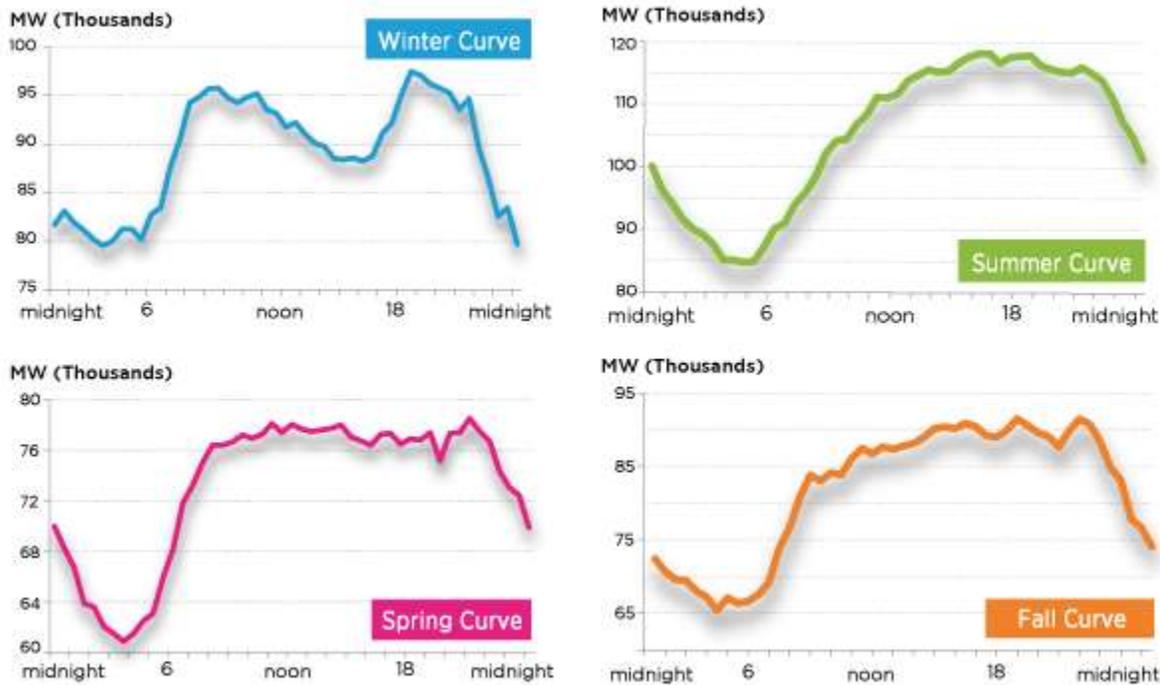
Electricity is the flow of electrons through a conductor. Electrical demand, the rate at which electricity is generated or consumed at any given point, is identified in terms of a watt.⁹ A watt is a unit of power or rate of doing work. For example, a 1,000-watt hair dryer demands 1,000 watts or a kilowatt (kW) to operate at any given instant. Electrical energy, the amount of work performed, is measured by a unit called a kilowatt hour (kWh), a kilowatt lasting one hour. Thus a 1,000-watt hair dryer operating for one hour consumes one kWh. Stated another way, the kilowatt hour is the basic unit for measuring how much electricity has been consumed, and the kilowatt tells how fast these units were used.

The voltage (V) of an electric system is the measure of electric pressure and is analogous to water pressure in a water system. For a pipe of a given size, raising the water pressure increases the capacity of the pipe to deliver water in gallons per hour. Similarly, for a wire of a given size, raising the voltage (pressure) results in an increase in the capacity of that wire to deliver energy. A third measure, the ampere (A) is frequently used to indicate the rating of appliances, fuses and wires in the home. The ampere is the measure of the flow of current, as distinguished from voltage (pressure). If an appliance is rated at 6A and the house voltage is 115 volts (V), the watts are 690 (115 x 6).

Electric load is the sum of customer demand (individually or in aggregate) at any given time. The amount of electricity being used is affected by many factors but mostly by temperature and time of day. Peak load is the highest point of demand over a period (e.g., annual or daily peak load). There are distinct patterns. Daily load is lowest in the middle of the night and highest during the day. There are also seasonal variations. For example, in the winter demand declines mid-day due to warmer day time temperatures. In the summer, demand continues to rise mid-day without relief for the same reason.

⁹ 1,000 watts equal 1 kilowatt (kW).

The following is a chart of PJM's¹⁰ daily load curves by season:¹¹



PJM's seasonal peak occurs pronouncedly in the summer and daily in the evening (6-8 PM; later in the winter), with the lowest daily demand occurring between 4-5 AM.

Load factor is average load as a percentage of peak load over a period of time, such as a day or month. A low load factor company is characterized by using energy inconsistently in sharp peaks and valleys. A high load factor is flatter. It is more expensive to serve a peak load. Generation, transmission, and distribution capacity is installed to meet that peak but may be needed only a few hours a year. Therefore, the more level the customer's load curve, the cheaper the average cost of providing service.

Load management, the promotion of a higher load factor, can result in significant savings, both short- and long-term. There are two basic approaches to demand response. One is granting to the supplier control over the customer's interruptible loads (such as air conditioners) and deferrable loads (such as water heaters, space-heating systems and swimming pool pumps) to shift load to off-peak periods. Industrial customers often agree to allow their power to be

¹⁰ PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

¹¹ <https://learn.pjm.com/three-priorities/keeping-the-lights-on/how-energy-use-varies.aspx>.

turned down (or off) during peak in exchange for a lower interruptible rate that recognizes the lower cost of service and the value of demand response.

The other approach implements a rate design that reflects on-peak/off-peak prices, including time-of-day (also called peak load pricing), and rewards the shift to off-peak period usage by charging less. The customer controls which appliances are used and when. Customers can defer operating nonessential appliances until the off peak when the rate is lower, or they may choose to pay the higher peak rates. The use of fixed monthly demand charges is another option.¹²

While the generation of electricity is no longer regulated by the Commission and customers are free to choose their own supplier, as described later in this section of the handbook, it is important to understand the generation side of the business.

As of this writing, electric energy cannot be stored on a large scale commercial basis, although battery technology development is evolving rapidly and soon will become an accepted part of load management. Otherwise, electricity must be generated and distributed in the amount customers require at the precise moment they require it. This means that there must always be sufficient generating, transmission, and distribution capacity to instantaneously meet customers' collective demand.

Electric energy is generated from other sources of energy (e.g., coal, oil, natural gas, nuclear, hydro, wind and solar) in a power generating plant, where an electrical generator converts mechanical energy to electricity.¹³ The most common turbine is steam driven.¹⁴ Water is heated to steam by burning fossil fuels (coal, natural gas or oil) or by a nuclear reaction. The steam is then released under pressure against the blades of the turbine, causing it to rotate. Different types of fuel used in steam plants present different characteristics and challenges.

In 2016, coal was 30 percent of generating capacity and provided 30 percent of the power generated in Pennsylvania; natural gas was 29 percent of generating capacity and provided 27

¹² These topics are further discussed in the rate design section of this handbook.

¹³ Or by the customer in the case of rooftop solar.

¹⁴ When an electric conductor, such as a wire, passes across a magnetic field (or vice versa) an electric current is set up in the conductor (the generator). In large power plants, the magnet is driven by a turbine and the magnet rotates inside a series of continuous wire coils. This rotation sets up a current, which is then transmitted and distributed by a utility to its customers. The turbine, which rotates the magnet, may be driven by a variety of energy sources.

percent of the power generated in Pennsylvania; nuclear was 24 percent of generating capacity and provided 38 percent of the power generated in Pennsylvania; hydro, wind, and miscellaneous plants were 7 percent of generating capacity and provided 6 percent of the power generated in Pennsylvania; and oil was 10 percent of generating capacity and provided 0.3 percent of the power generated in Pennsylvania.¹⁵

In a coal-fired plant, coal is crushed to dust, injected into a massive boiler, and ignited to superheat steam that turns a turbine. Uncontained, the combustion process is environmentally harmful and thus requires the installation of expensive cleansing equipment (e.g., “scrubbers”). The process may use oil and natural gas to create superheated steam.

Nuclear fission-powered plants in Pennsylvania are of two basic types: pressurized water reactors, such as Three Mile Island (Exelon Corporation), or boiling water reactors like the Susquehanna Steam Station at Berwick (Talen Energy). Nuclear fuel was once the least expensive of the energy sources used to generate electricity.¹⁶

Hydro power may be either run-of-the-river, such as the Holtwood Dam (Brookfield Renewable Energy Partners) in the lower Susquehanna River Basin, which employs the river’s current to generate power, or pumped storage, such as Muddy Run Station (Exelon Corporation), also on the Susquehanna, which pumps water up a hill at night during periods of relatively cheap power and allows it to return, generating power during peak demand periods. While hydro plants are very expensive to build relative to other sources of generation, their relatively low operating costs and extended life make them financially attractive.

For purposes of economic dispatch, generating plants are categorized into three basic groups: base load, intermediate and peaking. For example, coal and nuclear power plants can be operated continually as a base load unit and taken out of service only for scheduled maintenance and refueling. Solar and wind power produce, but only while the sun shines or the wind blows. Natural gas-fired units, once considered peaking units, now serve intermediate or base loads. Peaking plants vary in cost from oil-fired capacity to older, combustion turbines. These units provide power only a few hours per day and need to start and stop quickly.

¹⁵ PUC Annual Report: Electric Power Outlook for Pennsylvania 2016-2021, http://www.puc.state.pa.us/General/publications_reports/pdf/EPO_2017.pdf.

¹⁶ However, the full cost of spent fuel disposal is still not yet completely known.

Owners of generating facilities pool their generating capacity, using transmission lines to interconnect them. Each generating company's units, and the decision of when to operate them, are turned over to the Pennsylvania-New Jersey-Maryland Interconnection (PJM), which centrally dispatches generation from a computerized control center at Valley Forge in a competitive wholesale electricity market and manages the reliability of its transmission grid in all or part of 13 states.¹⁷ PJM's markets include energy (day-ahead and real-time), capacity, and ancillary services. Wholesale power pool pricing arrangements are regulated by the Federal Energy Regulatory Commission (FERC).

PJM provides monetary compensation to generators by two primary methods: the capacity and energy markets.¹⁸ The PJM capacity market holds a base residual auction each year for generation needed three years into the future. Generation resources bid into the auction until projected demand is met. The price is set for all generation by the highest bidder. Also, a prescriptive amount of demand resources participates, and is compensated the same as generation by providing "NegaWatts" of load side demand that can be shed if called upon by PJM. There are also incremental auctions held during the year, which are smaller balancing auctions where bidders can buy or sell their commitments to any resource to ensure PJM can reliably meet projected demand.

In the PJM energy market, all power generators are compensated for actual power generated. The energy market consists of a real-time (RT) energy market (five minutes ahead) and a day-ahead (DA) market (one day forward). The DA market ensures there are enough generation resources to meet the next 24-hour operating day to match supply with demand. The RT market refines and balances power generation every 5 minutes to more accurately reflect real-time energy usage.

¹⁷ <http://www.pjm.com/>. PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection. PJM became a fully functioning Independent System Operator (ISO) in 1996 and was designated a Regional Transmission Operator (RTO) in 2001. PJM has expanded beyond its original footprint and now coordinates in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, managing 165,569 mW of generating capacity, 792,314 gWh of annual energy and 82,564 miles of transmission lines. <https://www.ferc.gov/market-oversight/mkt-electric/pjm.asp>.

¹⁸ PJM's website displays real-time demand and generation data on the RTO. <http://www.pjm.com/markets-and-operations.aspx>.

The generation mix in Pennsylvania is changing. Both solar (photovoltaic) and wind power generation continue to make in-roads due to decreasing production costs and government market incentives. Pennsylvania's Alternative Energy Portfolio Standards Act of 2004 (Act 213) requires that an annually increasing percentage of electricity sold to Pennsylvania retail customers be derived from alternative energy resources (a total of 18% by 2021).¹⁹ To meet the requirements of Act 213, Electric Distribution Companies (EDCs) and Electric Generation Suppliers (EGSs) acquire alternative energy credits (AECs) in quantities commensurate with the required tier percentage.²⁰ As of May 2016, Pennsylvania had certified 12,638 alternate energy facilities, of which 8,897 are located within the Commonwealth.²¹ On October 30, 2017, the General Assembly passed Act 40, requiring solar projects used to fulfill Act 213 requirements to be located within the Commonwealth. Pennsylvania generates about 4% of its net electricity generation from renewable sources.²²

Natural gas generation has dominated the schedule of new plants coming online, while older, less efficient coal plants have been deactivated. As of year-end 2015, there were 6.5 gW of natural gas generation under construction in Pennsylvania, far ahead of all other fuel sources combined.²³

¹⁹ Alternative energy resources are categorized as Tier I and Tier II. Tier I resources include solar, wind, low-impact hydropower, geothermal, biologically-derived methane gas, fuel cells, biomass (including electricity generated in Pennsylvania utilizing byproducts of the pulping process and wood manufacturing process, including bark, wood chips, sawdust, and lignins in spent pulping liquors) and coal mine methane. Tier II resources include waste coal, demand side management, distributed generation, large-scale hydropower, byproducts of wood pulping and wood manufacturing, municipal solid waste, and integrated combined coal gasification technology. Act 213 requires that, by 2021, 8 percent of the electricity sold in each EDC service territory will be derived from Tier I resources. Energy derived from Tier II is to increase to 10 percent by that year.

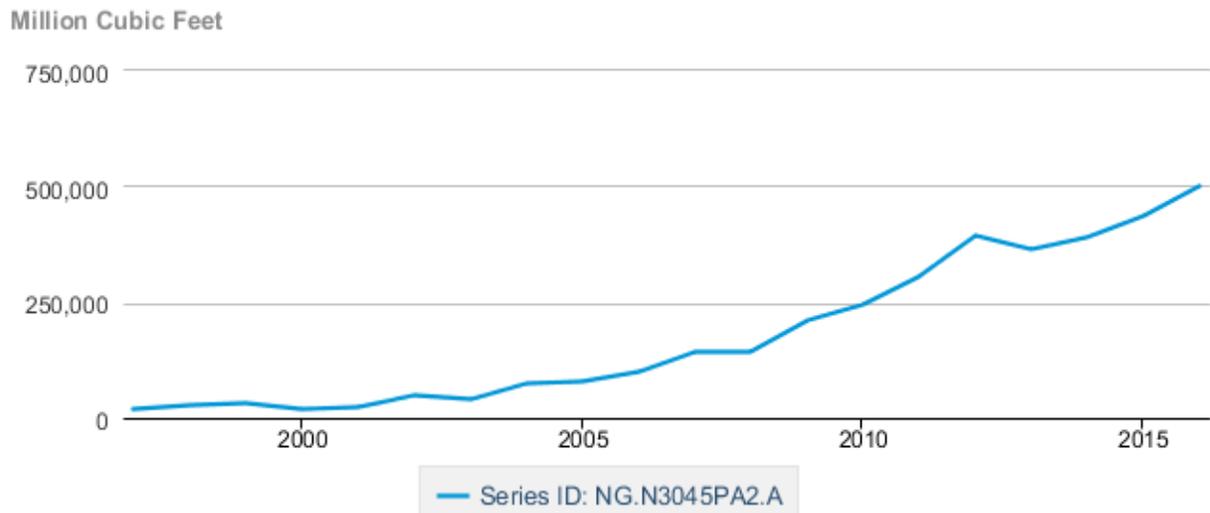
²⁰ An AEC represents one MWh of qualified alternative electric generation or conservation, whether self-generated, purchased along with the electric commodity, or purchased separately through a tradable instrument. An AEC can be sold or traded separately from the power. The Commission contracts with an AEC program administrator to verify that EGSs and EDCs are complying with the minimum requirements of Act 213 of 2004.

²¹ http://www.puc.state.pa.us/General/publications_reports/pdf/EPO_2016.pdf.

²² <https://www.eia.gov/state/analysis.php?sid=PA>.

²³ Data in this paragraph is from http://www.puc.state.pa.us/General/publications_reports/pdf/EPO_2016.pdf. As described below, electric energy is traded on a regional basis, and EDCs no longer own the generation facilities. Moreover, electrons flow to the area of need and are interchangeable (i.e., you don't negotiate for delivery of a particular electron).

Pennsylvania Natural Gas Deliveries to Electric Power Consumers, Annual



 Source: U.S. Energy Information Administration

Presently, nuclear-generated power is having a difficult time competing against low gas prices and improved gas generation technologies. Because of this difficulty in clearing the PJM market price, nuclear plant owners have begun to announce plant closures despite their continued operational viability and low carbon impact. In 2016, Pennsylvania nuclear power supplied 38 percent of the state's net electricity generation, more than from any other source and second in the nation.²⁴

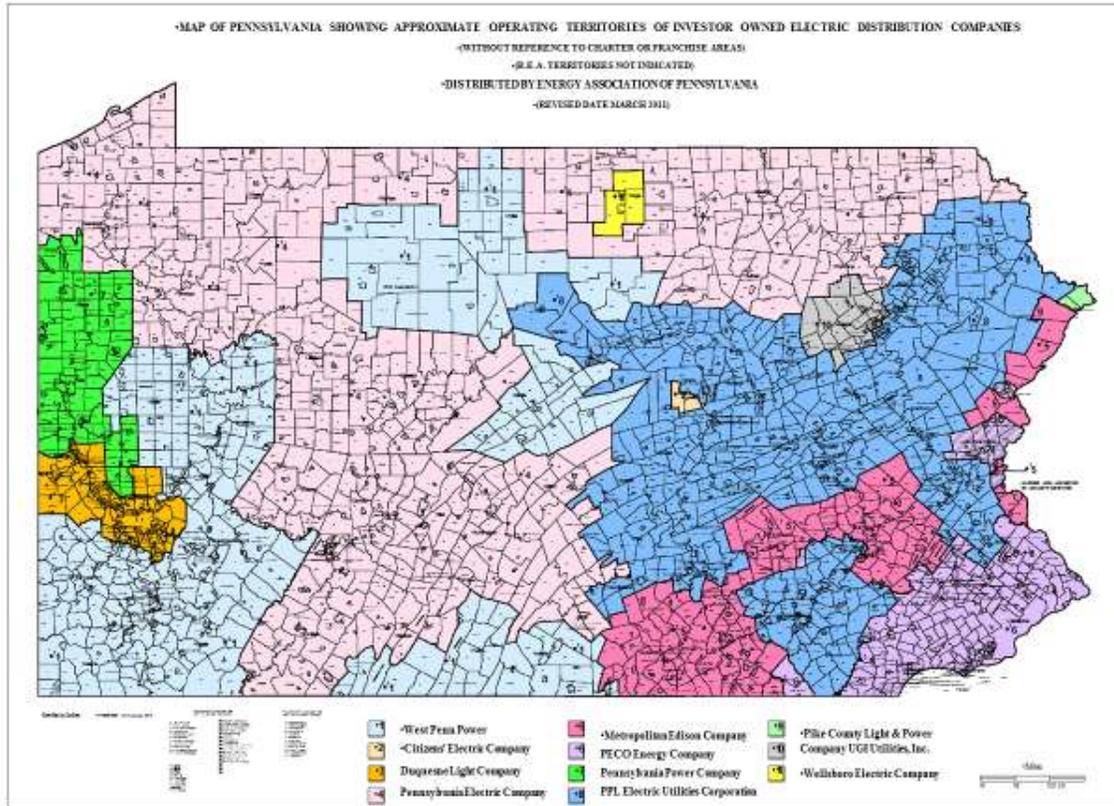
²⁴ <https://www.eia.gov/state/?sid=PA#tabs-2>



Once generated, power is transported through a system of wire conductor cables called transmission and distribution lines to the ultimate customer. The transmission system delivers bulk electric energy from the power generator at very high voltages (e.g., 500,000 or 230,000 volts) to regional substations, where it is transformed to lower transmission voltages (e.g., 138,000 or 69,000 volts) and delivered ultimately to distribution substations for conversion to distribution voltage levels (e.g., 33,000 or 13,000 volts).²⁵ The power is then sent through the distribution system and voltages are reduced to end-user levels; such as residential customer voltage (120/240 volts) or commercial customer (480/600 volts). Some larger commercial and industrial customers procure power at the transmission voltages.

²⁵ Transmission facility jurisdiction is shared with the FERC setting transmission rates and the states exercising authority over reliability, safety, and adequacy. See, *Petition of American Transmission Systems, Incorporated for a Declaratory Order*, Docket No. P-2013-2388149, Opinion and Order (Aug. 11, 2016). The FERC has established a seven-part-test to determine classification of facilities as distribution or transmission. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996). The statutory definition of “public utility” contained in Code §102 includes “facilities” that furnish transmission service, and Chapter 28 provides that electric transmission service should continue to be regulated as a “natural monopoly subject to the jurisdiction and active supervision of the Commission.” Code § 2802(16). States are preempted, however, from setting a different interstate transmission rate than the one set by FERC. 16 U.S.C. § 824(a); *Metro. Edison Co. v. Pa. PUC*, 767 F.3d 335, 341 (3d Cir. 2014). States exercise their traditional authority over reliability, safety, and adequacy of the bulk transmission system to the extent such actions are not inconsistent with federal standards. 16 U.S.C. § 824(o)(i)(3).

The EDCs' service territories are displayed on the following map:



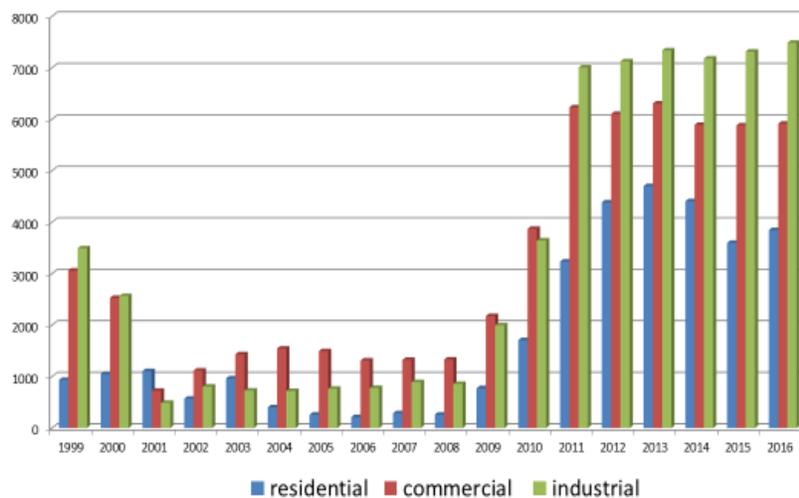
Investment, revenue, employee and customer statistics for 2016 are shown in the table below:

Utility	Total Net Utility Plant (\$)	Total Revenues (\$)	Total Employees	Customers by Class				
				Residential	Commercial	Industrial	Other	Total
Citizens	15,633,174	14,167,070	17	5,810	1,100	37	34	6,981
Duquesne	2,802,299,912	827,773,898	1,485	531,084	54,289	1,119	6,485	592,977
Met-Ed	1,982,080,492	784,484,270	653	497,407	65,892	869	596	564,764
PECO	7,553,111,124	2,327,603,151	2,210	1,456,585	150,142	3,096	9,823	1,619,646
Pennelec	2,363,497,924	809,485,730	728	502,098	83,981	851	693	587,623
Penn Power	503,081,139	246,656,442	183	143,961	20,592	153	85	164,791
Pike	19,011,370	2,542,273	2	3,736	1,004	0	5	4,745
PPL	7,986,196,291	1,737,700,558	1,837	1,243,915	179,345	3,825	1,541	1,428,626
UGI	1,246,877,282	87,241,392	69	54,385	7,442	154	64	62,045
Wellsboro	13,186,640	12,797,111	16	5,113	1,185	13	5	6,316
West Penn	1,735,288,064	938,573,572	708	624,721	86,912	12,263	525	724,421

Historically the local electric utility company was entirely responsible for both the generation (or purchasing) and the delivery of all electricity within its service territory. This arrangement was dramatically altered under Pennsylvania’s 1996 Electric Competition Act,²⁶ which required electric distribution companies (EDCs) to unbundle transmission, distribution and generation rates for retail customers and permitted competition for the supply (generation) component. The electric utilities shed themselves of all generation facilities by sale or by spinning the assets into a separate, unregulated supply company. The EDCs’ energy rates were capped. Stranded generation costs, as determined by the Commission, were packaged into a competitive transition charge and recovered from ratepayers as a non-bypass-able surcharge. Stranded cost recovery was completed in approximately 2010, at which time the rate caps were removed.

It has been very economical for Pennsylvania customers to shop for electricity in an open competitive market power from a competitive electric generation supplier (EGS) since the EDC caps came off in 2010.

CUSTOMER LOAD (MW) SERVED BY SUPPLIERS



Data Source: Pa Office of Consumer Advocate. <http://www.oca.state.pa.us/Industry/Electric/elecstats/ElectricStats.htm>

2

²⁶ Electric Generation Customer Choice and Competition Act (Competition Act) of Dec. 3, 1996 (P.L. 802, No. 138), codified at 66 Pa. C.S. §§ 2801, *et seq.*

In 2016, the 113 active EGSs were serving 36 percent of all electric service accounts and 68 percent of all load.²⁷ The PUC maintains a website to assist customers in making this choice.²⁸ The EDC is responsible for delivering the electricity (distribution and transmission) to those customers whom buy from an EGS and charges tariffed rates to do so.

The EDC also acquires electricity for customers who do not shop or when the EGS fails to provide the promised electricity, a function referred to as the “default service provider” (DSP). The Competition Act required that an EDC’s DSP rates be capped until the EDC completed its stranded cost recovery (the above market cost of its divested generating facilities). For most of these companies, generation rate caps expired Dec. 31, 2010.²⁹ The process of setting DSP rates is discussed in the surcharges section of this handbook.

Another sea change in the last 10 years has been the growth of customer-generated solar power and other small-scale, on-site power resources generically known as distributed generation (DG) or distributed energy resources (DER). Principal among these are rooftop solar photovoltaic (solar PV) and combined heat and power (CHP).

The growth of DG has been transformative for the distribution network operators, converting a one-way, command-and-control power flow to accommodate the participation of multiple small generators at the local, neighborhood level. The operational and rate design impacts of this emergent dynamic are myriad. In Pennsylvania, it is estimated that 413 gWh of potential (47.2 Mw of demand savings) can be realized with DG technologies by 2020, representing 0.3 percent of total energy sales.³⁰

Customer-generator systems sell power to the EDC when their systems are producing more electricity than is needed. EDCs are required to purchase this excess generation. Customer generators, however, typically cannot meet their entire daily or annual electricity needs and therefore buy power from the EDC when they are not sufficiently producing to meet their home

²⁷ http://www.puc.state.pa.us/Electric/pdf/Electric_Choice_Report-2016.pdf.

²⁸ www.PAPowerSwitch.com.

²⁹ After the expiration of these caps, which coincided with a dramatic reduction in worldwide energy prices, EGS competition began to strengthen considerably.

³⁰ The PUC commissioned a third-party study of the future potential of DR in Pennsylvania, which was published in 2015. <http://www.puc.pa.gov/pcdocs/1355000.pdf>.

load. The Commission has addressed both interconnection standards and compensation.³¹ Compensation under this arrangement is discussed in more detail later in the net metering section of this handbook.

Electrical storage is another emerging technology, and several states have begun to recognize and encourage its place as a distributed resource. Several states have passed policies supporting storage—such as mandates, tax incentives, streamlined permitting processes, and research and development programs. Several have also set procurement targets for energy storage. On Nov. 17, 2016, the FERC issued a notice of proposed rulemaking to remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary service markets operated by regional transmission organizations such as PJM.

Load management issues also continue to be front and center. Act 129 of 2008 imposes new requirements on EDCs with the overall goal of reducing energy consumption and demand.³² A 3 percent reduction in annual usage and a 4.5 percent reduction in peak demand has been targeted via plans submitted by those EDCs serving 100,000 customers or more. Implementation of the Energy Efficiency and Conservation Program (EE&C) plans is undertaken by conservation service providers. Act 129 also mandated full deployment of smart meters.³³ In January 2009, the Commission adopted an Implementation Order at Docket No. M-2008-2069887 establishing the standards each plan must meet and providing guidance on the procedures to be followed for submission, review, and approval of all aspects of EDC EE&C plans.³⁴ The work has been ongoing in electric energy conservation and is now in Phase III.³⁵

³¹ See Code §§ 1648.1-1648.8; *Final Rulemaking Re Net Metering for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act*, Docket No. L-00050174, Final Rulemaking Order (June 23, 2006). Regulations are also promulgated. Regs. §§ 75.11-75.51. See discussion of Net Metering later in this handbook.

³² Code § 2807.

³³ http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information/smart_meter_technology_procurement_and_installation.aspx.

³⁴ *Energy Efficiency and Conservation Program*, Docket No. M-2008-2069887, Implementation Order (Jan. 16, 2009).

³⁵ http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information/energy_efficiency_and_conservation_ee_c_program.aspx.

b) Natural Gas

Gas is measured both by volume (cubic foot) and heat content (British thermal unit or therms). The heat content of gas varies, and, since gas is purchased for its heat content, Btu is a more accurate measurement.³⁶ The average heat content of natural gas delivered to consumers can vary, depending on the other components of the mixture. The heat content often varies from under 1000 Btu per cubic foot to nearly 1100 Btu per cubic foot.³⁷ However, as industry shorthand, natural gas is often assumed to have a heat content of 1000 Btu per cubic foot.³⁸ The heat content of gas in the Marcellus Shale ranges from 1,000 to 1,400 Btu³⁹ and, since Pennsylvania Natural Gas Distribution Companies (NGDCs) have been increasing their use of Marcellus Shale gas, the heat content of Pennsylvania companies will tend to exceed 1,000 Btu.

Natural gas is a naturally occurring gaseous mixture of hydrocarbons and other gases consisting primarily of methane, which, unlike liquids, possess perfect molecular mobility and the property of indefinite expansion. By far, the largest sources of natural gas are natural formations. The conventional explanation is that natural gas was created from marine organisms compressed and heated by geological formations over millions of years. It is often found compressed in cavities or pores of rock.

There are four basic stages of delivery of natural gas: production, gathering, transmission and distribution. In the textbook example, gas flows from the wellhead to a small-diameter gathering line, then into a larger transmission pipeline, to a smaller-diameter distribution line, and, ultimately, to a small service drop (curb to house) and into the home.⁴⁰ Compressor stations are employed along the way to maintain system pressure and move the gas to the end user.

These functions are not usually vertically integrated into one company. The producer function at the wellhead (exploration and production) is often undertaken by a separate enterprise, which then sells the gas to a third party. These third parties can include an interstate

³⁶ Many meters, however, particularly residential, are capable of measuring volume only.

³⁷ https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm.

³⁸ Conversion tables may be found here: <https://www.eia.gov/tools/faqs/faq.php?id=45&t=8>. An Mcf is one thousand cubic feet and a Bcf is one billion.

³⁹ https://www.eia.gov/maps/pdf/MarcellusPlayUpdate_Jan2017.pdf.

⁴⁰ This is the configuration of a residential connection and probably is a fair description of most commercial service. Industrial customers take from larger distribution pipes or even transmission level facilities.

(pipeline) company, an aggregator, or an end-use customer. Pipeline companies transport the gas, often over thousands of miles, to the locale of the consumer (the city gate). At the city gate, the transmission company delivers the gas to the local distribution utility for delivery to the end user (the burner tip).

Drilling for natural gas is a speculative, risky venture. Generally, a person or corporation with an interest in exploring for and developing new gas sources will study the geological formation of an area, and, if the prospects look good, may drill a well. If gas is found close enough to an existing pipeline and a market is available, the producer can sell the gas. The landowner, on whose property the gas is found, is typically paid a royalty (usually one-eighth) of any revenues from the sale of the gas.

Natural gas is bought and sold as a commodity. Price varies based upon multiple factors including time of year, term of contract, reliability of delivery, quality and location. Wellhead prices are not regulated but rather are set in a competitive marketplace.

Shale gas is natural gas produced from shale rock formations. Because shale's permeability is too low to allow gas to flow in economical quantities, shale gas wells depend on hydraulically induced fractures (fracking) to allow the gas to flow. Synthetic natural gas (SNG) is produced from coal and oil. Other unconventional sources of methane include biomass, garbage, animal manures, coal seams, and oil shale gasification.

Pennsylvania is blessed with an abundance of naturally occurring energy resources—coal, oil, and natural gas. Titusville, Venango County, was the birthplace of the modern petroleum industry a century and a half ago (1859) when Edwin Drake drilled the world's first successful commercial oil well (associated with natural gas). Coal mining began in 1761 at a location in what is now downtown Pittsburgh.⁴¹ Since that time, Pennsylvania has played a central role in America's energy sector.

The advent of Marcellus Shale-related drilling has had a dramatic impact on Pennsylvania's natural gas production levels, with production in 2016 more than 25 times that of

⁴¹ Pennsylvania was the third-largest coal-producing state in the nation in 2016 and the only state producing anthracite, which has a higher heat value than other kinds of coal. <https://www.eia.gov/state/?sid=PA>.

2008.⁴² Gross natural gas production, primarily from the Marcellus Shale, exceeded 5 trillion cubic feet in 2016, and Pennsylvania was the nation's second-largest natural gas producer for the fourth consecutive year.⁴³ Until the commercial scalability of shale fracking, the largest finds of natural gas were in the southern and western United States. Marcellus shale production has risen from 2 billion cubic feet per day (Bcfd) in January 2010 to over 19 Bcfd in June 2017.

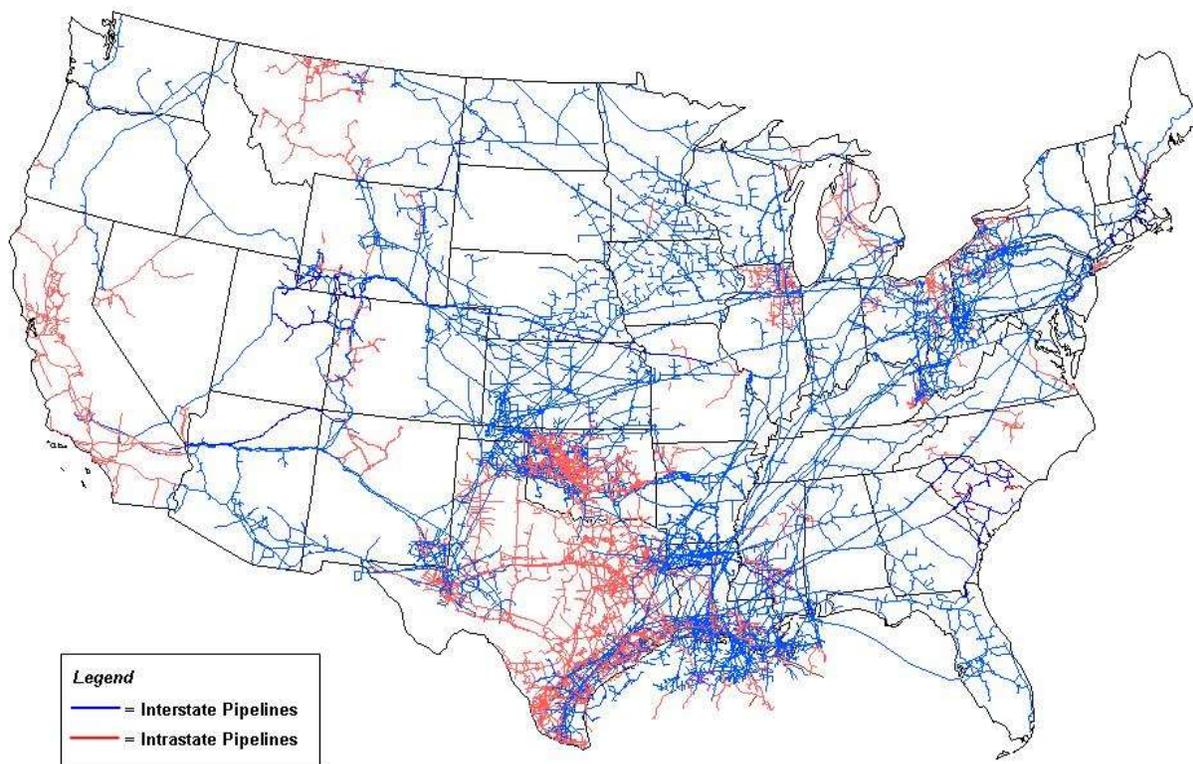
Before it can be used as fuel, natural gas generally must be processed to remove impurities, including water, to meet the specifications of marketable natural gas. These byproducts include various usable natural gas liquids (NGLs), such as ethane, propane, butane, and pentane, as well as hydrogen sulfide, carbon dioxide, water vapor, and, sometimes, helium and nitrogen.

Regionally, 20 interstate natural gas pipelines operate in the northeastern United States.⁴⁴ These interstate pipelines deliver to more than 50 local distribution companies (LDCs), natural gas-fired electric generating facilities, and large industrial concerns in the region. The pipelines in Pennsylvania have access to natural gas production from the South and Midwest; from the Rockies via the Rockies Express Pipeline; from Canada; and from the Marcellus and Utica Shales, spanning large portions of Pennsylvania, Ohio, and West Virginia.

⁴² The current Marcellus shale play began when Range Resources drilled a well in 2003 to the Lower Silurian formation in Washington County, PA.

⁴³ <https://www.eia.gov/state/?sid=PA>.

⁴⁴ Transmission pipelines transporting natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (NGA), 15 USC § 717(a) et seq. FERC issues certificates of public convenience to these pipelines and conducts siting proceedings to determine the specific route of the pipeline. The NGA preempts most state regulation of these "interstate" pipelines. *Northern Natural Gas Company v. State Corporation Commission of Kansas*, 83 S.Ct. 646 (1963), but see *Oneok, Inc. v. Learjet, Inc.*, 135 S.Ct. 1591 (2015) (certain state antitrust laws may not be subject to preemption). Transmission pipelines transporting hazardous liquids in interstate commerce are regulated by FERC under the Interstate Commerce Act (ICA), 49 USC §§ 10101-16106. Hazardous liquids include commodities such as refined petroleum products, natural gas liquids and other flammable fuels. 49 USC § 60101. The ICA does not preempt state regulation of intrastate service on intrastate pipelines. *In re Condemnation by Sunoco Pipeline, L.P.*, 164 A.3rd 1000 (Pa. Commw. Ct. 2106), allocator denied, 164 A.3d 485 (2016). FERC does not issue certificates of public convenience or conduct siting proceedings for interstate hazardous liquids pipelines.



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Marcellus Shale development has dramatically altered interstate pipeline flows, which have begun to move south, rather than north, for the first time in more than 50 years, due to the large injections of Pennsylvania gas. The current challenge is the construction of new pipelines to transport the Marcellus shale production to market. There were 5.2 Bcfd of pipeline projects slated to come online in 2016 in the northeast region and 19.5 Bcfd of capacity scheduled for 2017.⁴⁵

In 1992, the FERC began transitioning to an open, equal access market. Prior to Order 636,⁴⁶ the interstate pipelines sold natural gas to their primary customers, the local gas utilities, on a “bundled” basis so that the commodity and delivery were one price and could not be purchased separately. Under Order 636, transportation was “unbundled” from sales and required

⁴⁵ http://www.puc.state.pa.us/NaturalGas/pdf/Gas_Outlook_Report-2016.pdf.

⁴⁶ *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, 59 FERC ¶ 61,030, FERC Stats. and Regs. ¶ 30,939 (1992).

to be offered on an open access (non-discriminatory) basis. Firm and interruptible transportation services were introduced. In February 2000, FERC issued follow-up Order 637⁴⁷ instituting refinements to and improving the usefulness of the capacity release program. This very simple but profound alteration to the gas industry defines the market to this day.⁴⁸ Gas transportation, as you might imagine, is a complicated attempt to organize multiple shippers and contracts, pairing producer and customer delivery in a way that keeps the pipeline delivery system in balance.

In 1987, five years prior to FERC Order 636, the PA PUC implemented a series of orders to require the transportation of customer-purchased gas volumes by the gas utilities “without discrimination as to type and location of customer.”⁴⁹ Important auxiliary services, such as standby sales and storage service, were developed to assist the customer and natural gas distribution companies (NGDCs) in avoiding unmanageable over/under delivery conditions. The market focus was larger customers.

There are 31 regulated NGDCs in Pennsylvania, and 10 of these earn gross revenues greater than \$40 million per year. Peoples, made up of the Equitable Division and the Peoples Division, when viewed as one entity, is the largest NGDC.⁵⁰ Peoples also operates Peoples Gas (formerly Peoples TWP) as a separate NGDC. PECO Gas is the largest stand-alone NGDC in Pennsylvania. The City of Philadelphia-owned Philadelphia Gas Works (PGW) is a close second. Columbia Gas and National Fuel Gas also operate in the Commonwealth. UGI operates multiple distribution companies (UGI – Gas Division, UGI - Central Penn Gas, and UGI - Penn Natural Gas). The NGDC territories and select interstate pipelines are shown on the map below.⁵¹

⁴⁷ *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, FERC Stats. & Regs. ¶ 31,091 (2000).

⁴⁸ Commission implementation rules for Pennsylvania’s NGDCs are found at Regs. § 69.341 *et seq.*

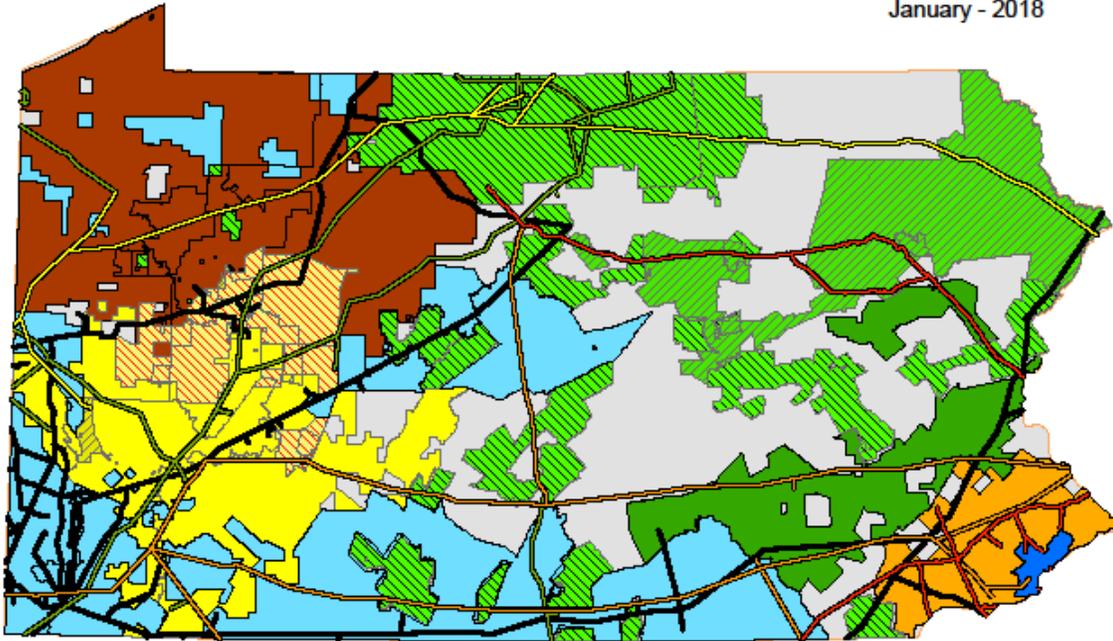
⁴⁹ Regs. § 60.3.

⁵⁰ Peoples Natural Gas acquired Equitable Gas in 2013 and now operates them as one company with two divisions.

⁵¹ Provided by UGI Energy Services, LLC.

Select Pennsylvania LDCs and Interstate Pipelines

January - 2018



Select Interstate Gas Lines	Western Utility Territories	Eastern Utility Territories
Operator	Operator Name	Operator Name
— Columbia Gas Trans Co	— National Fuel Gas Distribution	— Philadelphia Gas Works
— Dominion Transmission Co	— Peoples Natural Gas Co (The)	— PECO Energy Co
— Tennessee Gas Pipeline	— EQT Gas Co	— UGI Utilities Inc
— Texas Eastern Trans Co	— T W Phillips Gas & Oil Co	— UGI Penn Natural Gas Inc
— Transcontinental Gas PL	— Columbia Gas of Pennsylvania Inc	— UGI Central Penn Gas

Pennsylvania NGDC operating results for 2016 are as follows:

Utility	Total Net Utility Plant (\$)	Total Revenues (\$)	Unaccounted for Gas (%)	Customers by Class				
				Residential	Commercial	Industrial	Other	Total
Columbia	1,634,170,091	477,706,131	0.56	388,830	37,149	269	0	426,248
National	374,033,715	173,479,310	0.69	198,419	16,034	594	0	215,047
PECO	7,553,111,124	454,445,127	2.95	472,606	44,048	396	14	517,064
Peoples⁵²	1,841,873,412	319,362,603	6.35	335,323	27,656	255	12	363,246
Equitable Peoples	1,841,873,412	239,001,091	6.35	244,483	20,768	150	26	265,427
TWP	223,747,562	77,675,117	7.08	57,207	4,292	27	5	61,531
PGW	1,300,423,449	576,323,502	3.77	477,764	24,676	4,796	4,021	511,257
UGI	1,246,877,282	379,732,914	0.07	346,756	38,264	1,337	0	386,357
UGI CPG	338,806,566	121,999,868	1.69	71,399	10,898	305	0	82,602
UGI Penn	695,022,101	192,817,518	0.87	153,022	16,686	220	0	169,928

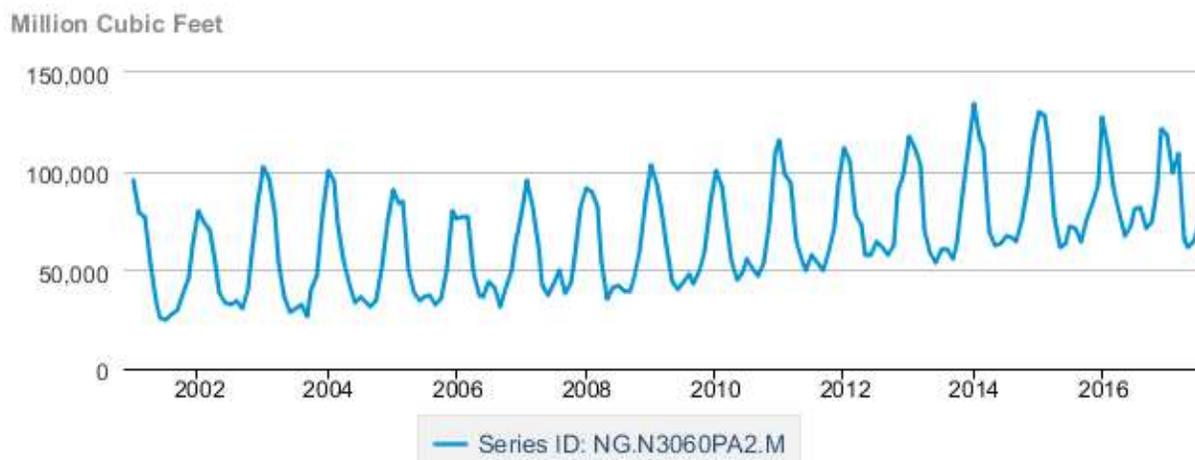
There are nearly 3 million natural gas customers in Pennsylvania, of which about 2.7 million are residential customers. In 2015, 51 percent of Pennsylvania households used natural gas as their primary home heating fuel.⁵³ This figure is growing as NGDCs seize the opportunity to expand their customer base with the surplus of the Marcellus Shale formation. Conservation and appliance efficiency have driven down average residential usage from approximately 120 Mcf per year 20 years ago to the current average of about 77 Mcf per year per household.

As in the electric industry, gas customers' demand for service (load) varies from hour to hour and season to season. As one would expect, the system demand for gas is higher during the day and lower at night. Demand for gas, more than any other utility service, is temperature-sensitive because a major end use of the service is heating. Therefore, gas companies experience their system peak in the winter. The annual peak is very pronounced.

⁵² Peoples and Equitable report Total Net Utility Plant as a combined system and Total Revenues separately.

⁵³ 22 percent used electricity and 18 percent used fuel oil. Other heating fuels used in the state include propane, wood, and coal. <https://www.eia.gov/state/?sid=PA>.

Natural Gas Delivered to Consumers in Pennsylvania (Including Vehicle Fuel), Monthly



 Source: U.S. Energy Information Administration

(Note the record-setting winter peak during the very cold polar vortex of 2014)

Distribution company sales load is served by purchases delivered by interstate pipelines, local production, and other sources. Supplier contracts and pipeline rate design encourage high load factors (i.e., a steady rate of flow) and discourage purchase patterns with sharp peaks and valleys. Producer contracts have minimum take (or pay) provisions. There are severe penalties imposed by the pipelines for under deliveries on cold days.

Unlike the electric industry, natural gas is easily and commonly stored for future use. The pipelines themselves are simply pressurized vessels and, at greater pressures, can store greater volumes. Moreover, several companies, both NGDs and pipelines, operate underground storage reservoirs in Pennsylvania where gas is injected during the summer months when prices are lower and withdrawn during the winter months of demand. Total Pennsylvania storage capacity for 2015 was 771 Bcf. Storage is an important component of balancing and purchasing gas at a higher load factor.

Winter demand is also sometimes met by utilizing propane facilities and liquefied natural gas (LNG) facilities. As it gets colder and demand starts to rise, gas companies manage

winter load both on the supply and customer side. On the supply side, the gas company may introduce other, non-pipeline supplies of gas into the system. Many distribution companies store gas taken from the pipeline company during a period of low demand (at a lower price in the summer) in old, exhausted gas wells or storage tanks. This stored gas is then withdrawn and used in place of more expensive peak gas or when other sources of gas are insufficient to meet demand.

Some companies, PECO and PGW for example, liquefy off-peak pipeline purchases of natural gas and then gasify it at peak periods. Storing propane to introduce into the system is a third way to meet peak energy demands. A fourth technique is to increase compression or “pack” the pipeline system, boosting deliverability. On the customer side, the NGDC may restrict or cease service to industrial customers who may have volunteered for interruptible service (in exchange for lower rates).

The Pennsylvania PUC regulates and controls services to the retail customer. The larger portion of the NGDC’s retail price, about 60 percent as a rule of thumb, is the cost of distribution service.⁵⁴ The remaining 40 percent of the bill, the cost of the gas supplied, is a pass-through to the consumer.

Sharing ideas with the introduction of customer choice into the electric markets, the Natural Gas Choice and Competition Act was signed into law on June 22, 1999, by Governor Tom Ridge, revising the Code by adding Chapter 22, which restructured the natural gas industry. Switching regulations were adopted on July 7, 2000, and became effective July 8, 2000.⁵⁵ Residential customers may now purchase gas from a third-party supplier, and the NGDC is obligated to transport gas on behalf of the customer.⁵⁶ The Commission maintains a website to assist customers in selecting an alternative natural gas supplier (NGS).⁵⁷

⁵⁴ The distribution cost percentage varies for each gas utility. The lowest percentage in Pennsylvania was 43 percent as of Jan. 31, 2017 (UGI – Gas Division), with the highest being 76 percent (Peoples T.W. Phillips)

⁵⁵ Regs. § 59.91 *et seq.*; *See Final Rulemaking Order re: Rulemaking Establishing Procedures to Ensure Customer Consent to a Change of Natural Gas Supplier*, Docket L-00990145 (Order entered May 12, 2000)

⁵⁶ Again, like electricity, the actual contracted for molecules are not transported to the customer. Delivery is by displacement.

⁵⁷ <http://www.pagasswitch.com/>.

c) Water

More than any other public utility service, water is essential to human life. Water sales are measured volumetrically by units of one thousand gallons (Mgal) or one hundred cubic feet (Ccf). The source of supply and distribution systems for water are generally local. In this part of the country, the long-distance transmission of water is virtually nonexistent.

Most major cities in Pennsylvania, including Philadelphia, Pittsburgh, and Erie, are served by municipally owned and operated systems. About 1 million Pennsylvania households rely on 450,000 individual wells in the Commonwealth, and 10.5 million Pennsylvanians consume water supplied by 2,100 community drinking water systems (which includes investor-owned water utilities).⁵⁸

In 2016, there were 134 water and wastewater utilities operating in Pennsylvania under the Commission's jurisdiction. Of these, 82 were water utilities, both private and public (i.e., municipalities operating outside of their municipal limits) and 52 were wastewater utilities, including both private and public operations.

Pennsylvania American is the largest privately-owned private water/wastewater utility operating in Pennsylvania, delivering 46 billion gallons of water in 2016. Aqua Pennsylvania is also a very large company, with 430,000 customers consuming 35 billion gallons of water. York Water (66,000 customers) is a distant third, followed by Suez Water (59,000 customers).

⁵⁸ http://www.puc.state.pa.us/general/consumer_ed/pdf/waterbrochure.pdf.

Important Class A water company statistics include the following:

Utility	Total Net Utility Plant (\$)	Total Revenues (\$)	Customers by Class				
			Residential	Commercial	Industrial	Other	Total
Aqua	3,086,101,720	401,662,919	393,235	22,194	797	14,333	430,559
Audubon	4,032,594	2,303,144	2,613	157	0	103	2,873
Can Do	5,365,340	1,796,741	0	19	78	1	98
Columbia	45,272,082	6,275,837	9,540	508	36	141	10,225
Newtown	37,595,906	5,679,496	9,602	636	45	246	10,529
PA-American	3,642,598,264	601,460,807	602,856	44,812	522	6,580	654,770
Suez Bethel	7,513,827	1,072,975	2,421	70	0	26	2,517
Suez PA	253,475,721	43,677,897	54,112	4,691	51	1,293	60,147
Superior	25,734,007	3,226,808	3,897	90	0	241	4,228
York	269,500,542	45,226,616	60,350	4,253	301	1,504	66,408

Many water utilities rely upon groundwater wells for water supply, pressuring the water by electric pump and employing pressurized tanks and booster pumps to transmit water to higher elevations. Water may also be pumped into elevated tanks to keep system pressures up and an adequate supply available. Some systems employ an extensive series of impounding reservoirs or dams and are largely gravity systems, thus avoiding the expensive pumping requirements of other companies. Others obtain their supplies from lakes, streams, or rivers; collectively referred to as surface waters. Surface water treatment for water utilities is typically costlier than treating groundwater, as surface water treatment requirements are more demanding. The requirements for surface water treatment include flocculation, clarification, and filtration, which are not typically needed for groundwater treatment.

Typical load curves of water companies reflect twice-daily demand peaks in the morning and evening. The annual peak occurs during the summer, with the maximum daily demand often occurring in the evening. Like the other industries, sales per customer are diminishing due to conservation and efficiency efforts. Customers may be metered or pay a “flat” fee for unlimited use of water. The PUC has mandated a program of universal metering.⁵⁹

⁵⁹ Regs. § 65.7.

Both the Public Utility Code⁶⁰ and the Pennsylvania Safe Drinking Water Act,⁶¹ as administered by the Pennsylvania Department of Environmental Protection (DEP), confer jurisdiction over the quality of water service. The Commission’s water regulations⁶² address the service-related topics of water pressure, metering, and facility construction but do not set potable water standards for the presence of microbiological, chemical, radiological, or other contaminants. These are controlled by the Department of Environmental Protection’s Safe Drinking Water regulations.⁶³

The Commonwealth has a policy of encouraging well-operated water and wastewater utilities to regionalize or consolidate with smaller systems. Operational constraints inherent to small systems typically include: quality compliance problems, limited technical and managerial expertise, lack of capital for improvements with a limited ability to borrow at reasonable rates, deferred maintenance, deteriorated and undersized infrastructure, and minimal sources of supply or storage. The Commission’s stated policy is to “substantially restrict the number of nonviable drinking water systems by discouraging the creation of new nonviable small systems, and at the same time, encourage the restructuring of existing nonviable small systems.”⁶⁴

Code § 1327, enacted in 1990, offers a rate base valuation equal to the acquisition cost⁶⁵ to public utilities acquiring small “troubled” water and wastewater companies, private or municipal. There are several basic rules.⁶⁶ The system must have 3,300 or fewer customer connections or be nonviable absent the acquisition. The acquired entity must be distressed and

⁶⁰ Code § 1501. The Commission’s statutory authority is general; “Every public utility shall furnish and maintain adequate, efficient, safe, and reasonable service and facilities...”

⁶¹ 35 P.S. §§ 721.1 - 721.17. DEP’s Bureau of Safe Drinking Water website can be found here: <http://www.dep.pa.gov/Business/Water/BureauSafeDrinkingWater/Pages/default.aspx>.

⁶² Regs. § 65.1 *et seq.*

⁶³ 25 Pa. Code § 109.1 *et seq.*

⁶⁴ Regs. § 69.701 (adopted 1994).

⁶⁵ i.e., an increase in rate base valuation beyond the typical original cost. If original cost is higher, then the difference is “amortized as an addition to income over a reasonable period of time...” Code § 1327(e).

⁶⁶ Code § 1327(a).

“...not, at the time of acquisition, furnishing and maintaining adequate, efficient, safe and reasonable service and facilities...”⁶⁷

In 1996, the Commission expanded its toolkit of “acquisition incentives” where the acquired system has less than 3,300 customer connections and is not viable, to also include:

- A rate of return premium for the acquiring utility;
- A debit acquisition adjustment;
- The deferral of acquisition improvement costs; and
- A plant improvement surcharge.⁶⁸

These efforts have been successful. The original 1983 Rate Case Handbook reported that there were 333 private water companies operating in Pennsylvania, and despite extensive land development since that time, there are now 60 private water companies regulated by the Commission.

In 2012, Governor Tom Corbett signed Act 11 of 2012, which amended § 1311 of the Code. This legislation allows utilities that provide water and wastewater service to petition the Commission to combine water and wastewater revenue requirements. This enables the Commission, when setting base rates, to allocate a portion of the wastewater revenue requirement to the combined water and wastewater customer base if in the public interest.

Most recently, Governor Tom Wolf signed Act 12 of 2016, which added § 1329 to the Code. This legislation enables a public utility or entity (buyer) to utilize fair market valuation when acquiring water and wastewater systems that are owned by a municipal corporation or authority. Adverse operating conditions for the acquired company need not be present. The effects of Act 11 of 2012 and 12 of 2016 are discussed in the rate base section of this Handbook.

⁶⁷ Including violation of statutory or regulatory requirements concerning the safety, adequacy, efficiency, or reasonableness of service and facilities; inadequate financial, managerial, or technical ability of the small water or sewer utility; a present deficiency concerning the availability of water, the palatability of water or the provision of water at adequate volume and pressure; necessary improvements to plant or distribution system cannot reasonably be expected to furnish and maintain adequate service to its customers at rates equal to or less than those of the acquiring public utility; or any other facts, as the commission may determine, that evidence the inability of the small water or sewer utility to furnish or maintain adequate, efficient, safe and reasonable service and facilities.

⁶⁸ Regs. § 69.711.

d) Telephone

Traditionally, telephone rates were calculated based on the beginning point and ending point of a call. Telephone customers were billed a flat rate for unlimited calling within a defined local calling area for each telephone number (i.e., access line) to which they subscribed. Calling outside of that local calling area incurred a per-minute charge measuring the duration of the toll call (i.e., minutes of use).

In today's pricing structure, however, toll and local calling service are generally bundled together into a single, "all you can eat" price for calls within the U.S. These voice service bundles have become very popular among wireline customers and typically include a flat monthly rate for unlimited local and toll calling. Moreover, many of today's wireline voice customers also receive other services. Customers receiving voice and data/internet service from the same provider often are referred to as receiving a "double play", while customers receiving voice, internet, and video services from the same provider often are referred to as purchasing the "triple play."

Voice service requires a relatively low bandwidth. Internet access is measured based on bandwidth: the rate of successful data transfer is measured in megabits per second (Mbps). To put the bandwidth measurements into perspective, a maximum 100 Kbps⁶⁹ upload and download speed is all that is needed for internet voice service. For web surfing and video streaming, a consumer is receiving more data than he or she is sending, and there is a wide range of speeds needed depending upon the quality of the imaging, the size of the consumer's screen, and the number of users at one time, among other considerations. The speed range required for these tasks is somewhere between 3-10 Mbps in the download direction.⁷⁰ For most customers, lesser speeds are needed in the upstream direction. Carriers retail their services usually in packages of speeds (low to high).

Of all the utility industries, technology has driven "telecommunications" to places that were previously unimaginable. In the original 1983 handbook, "telephone service" was described as the transmission of voice communications between points over a pair of copper wires using electrical impulses. At that time, there was little or no choice of local phone provider, and the

⁶⁹ 1,024 Kbps equals 1 Mbps.

⁷⁰ <https://www.fcc.gov/research-reports/guides/household-broadband-guide>.

latest development was the customer's newly-granted ability to choose a long-distance carrier. There was no internet, no cell phone service (or if there was service, it was limited geographically and completely unreliable), no smart phones, and no cable telephone alternative. The changes since 1983 have been truly astounding, and our lives have been profoundly affected.

Once a cradle-to-grave monopoly, "Ma Bell" operated a national network for all voice calling, even owning the phones and the wiring inside the customers' premises.⁷¹ The "independent" phone companies filled in the geographic spaces where the AT&T monopoly did not serve. As other companies pressed to enter the telephone business, the Federal Communications Commission (FCC) responded by permitting competition for long-distance (toll) calling, the phones and switchboards (customer premises equipment), customer premises wiring (inside wire), and other physical aspects of the network.

A major regulatory transformation occurred with the 1984 divestiture of AT&T⁷² based upon a US Department of Justice antitrust lawsuit that forced the national monopoly to break up into seven regional local service companies⁷³ and left AT&T Long Lines as a stand-alone long-distance service provider. Independent interexchange carriers (IXCs) were encouraged to enter the market for toll service, and companies like MCI and Sprint eagerly expanded their services.

The ensuing federal Telecommunications Act of 1996 (TA 96) wrought many changes to the telecommunications regulatory landscape, principal among them the requirement that the local exchange network of the RBOCs and other "incumbent" local exchange carriers (ILECs) be unbundled and made available for use by competitors (CLECs). This jumpstart of local service competition allowed the CLECs to employ various business models that used all or a part of the ILEC's network. In this way, competitors avoided the need to replicate facilities to enter the marketplace. Once the FCC, in consultation with the state commissions, was satisfied that local market in the RBOC service territory had been "irreversibly opened" to competition, employing

⁷¹ AT&T's local telephone monopolies accounted for 80-85 percent of access lines nationally in 1982.

⁷² https://en.wikipedia.org/wiki/Breakup_of_the_Bell_System; See <https://www.justice.gov/atr/att-divestiture-was-it-necessary-was-it-success> for a 2007 discussion of the structural separation impacts.

⁷³ The so-called regional Bell operating companies (RBOCs) or (Bell Atlantic) "Baby Bells" providing local and "regional" toll. Verizon is the successor to an RBOC in the mid-Atlantic region.

a detailed 14-point check list, the RBOC was entitled to re-enter the long-distance market without limitation.⁷⁴

The introduction of competition also involved the development of interconnection agreements between the ILECs and CLECs for physical interconnection, as well as the exchange of traffic and compensation. This was done by agreement or, failing that, arbitration before the state commission.⁷⁵ The mandating of number porting (i.e., the ability of a customer to keep his or her telephone number when switching providers) also expedited the conversion to a competitive market for local services.

An even more powerful competitive trend in voice service, however, has been the ascendancy of independently-operated telecommunications platforms using different technologies that offer similar, fungible services, allowing consumers a choice. The almost exponential growth of wireless network availability and capacity has made mobile voice service almost ubiquitous in Pennsylvania. Traditionally TV only, the cable companies also have entered the telecommunications fray to offer voice service. Satellites offer a fourth service platform for voice service.

Moreover, what was once a siloed set of separate services provided by separate service providers has now converged. Where Verizon (landline) was a supplier of only voice services twenty years ago, it now also offers internet access (ISP) and TV programming. Comcast has expanded its cable TV broadcasting platform to now include ISP and voice services. Verizon Wireless and AT&T Wireless, as well as satellite companies, have jumped into these diversified product markets with product bundles of their own.

The most dramatic revolution, however, has been the expansion of the internet and the content it provides. The amount of data transport now carried is magnitudes beyond the voice traffic that Ma Bell carried over its original copper wire, TDM-based network.

In this constantly evolving and expanding telecommunications landscape, the Commission's ratemaking role has remained focused on traditional wireline telephone voice

⁷⁴ The PA PUC did so in June 2001. *Application of Verizon Pennsylvania, Inc., et al., for Authorization Under Section 271 of the Communications Act to Provide In-Region, InterLATA Service in the Commonwealth of Pennsylvania*, CC Docket No. 01- 138, Consultative Report of the Pennsylvania Public Utility Commission (June 25, 2001). The FCC subsequently agreed.

⁷⁵ 47 USC § 252.

services. The Pennsylvania General Assembly has maintained a consistent stance that competition should evolve without regulation. The technology of “mobile domestic cellular radio” (CMRS; i.e., mobile wireless) is expressly excluded from the definition of “public utility” in the Code and, hence, not subject to Commission jurisdiction. Also excluded from state regulation (for the most part) are cable telephony and any other forms of internet protocol (IP)-based telecommunications.⁷⁶ Moreover, the FCC has affirmatively taken jurisdiction over retail internet access service rates, terms, and conditions, leaving little say for the states in this space.

Even the Commission’s traditional authority over intrastate voice services has shrunk. In the arena of local service competition, the TCA 96 largely preempted the states and imposed a rigorous set of rules that the states are required to follow. In 2011, the FCC seized jurisdiction over compensation between carriers for the exchange of toll traffic, including calling within a state, imposing a federal regime of “bill and keep” (i.e., zero) compensation.⁷⁷

The regulatory space left for the PUC is constricted. The Commission retains quality of service jurisdiction over the non-VoIP (voice over internet protocol) services provided by ILECs and CLECs. The Commission also retains rate jurisdiction for traditional, standalone ILEC local voice service when it is not bundled with another service (e.g., TV programming or internet access).

The Commission also has limited authority over the ILEC deployment of “broadband” service (e.g., internet access) under Chapter 30, basically to ensure that the minimum capacity standards of that statute are maintained.⁷⁸ Chapter 30 of the Code⁷⁹ stipulates a revised regulatory regime for the ILECs that volunteer to deploy a broadband network throughout their service territory that offers, through any technology, a minimum down speed of 1.544 Mbps and an up speed of at least 128 Kbps to any customer within 10 days of request. In exchange, ILECs are granted some level of de-tariffing of “competitive services” and a simplified, ratemaking formula for services that remain rate regulated. The ILECs have filed plans that define the new

⁷⁶ Voice-Over-Internet Protocol Freedom Act, P.L. 627 of 2008, codified at 73 P.S. §§ 2251.1, *et seq.*

⁷⁷ *In re Connect America Fund et al.*, WC Docket No. 10-90 *et al.*, FCC 11-161 (Nov. 18, 2011).

⁷⁸ As noted previously, however, internet access service rates, terms and conditions are controlled by the FCC.

⁷⁹ Chapter 30 of Title 66 of the Public Utility Code was originally enacted in 1993 (Act 67 of 1993) and was then subsequently reenacted in 2004 (Act 184 of 2004). The Chapter 30 speed standards of 1.544 Mbps (down) and 128 Kbps (up) are very low by current FCC standard for advanced services, which are 25 Mbps (down) and 3 Mbps (up).

form of regulation and their deployment commitments, which have been approved by the Commission.

All jurisdictional ILECs have achieved their Chapter 30 network modernization plans and operate under some form of alternative ratemaking. They all are required to act as the “carrier of last resort” for both voice and broadband deployment, which their competitors are not.

Verizon is the largest ILEC in Pennsylvania, serving approximately 85% of the ILEC customer base and all the major Pennsylvania cities. The remaining ILEC lines are served by approximately 30 independent companies. The following table lists Pennsylvania’s major ILEC wireline carriers by net plant and revenues for 2016:

Utility	Total Net Utility Plant (\$)	Total PA Revenues (\$)	Company-wide Revenues (\$)
Verizon PA	1,911,968,000	667,497,000	3,234,634,000
United (CenturyLink)	100,486,808	80,861,118	217,222,741
Verizon North Commonwealth (Frontier)	46,533,000	75,069,000	205,194,000
Windstream PA (Alltel)	423,632,165	67,206,119	119,931,392
	141,300,341	60,788,715	116,048,948

The traditional ILEC business model is in decline and has been for many years. As alternatives developed, customers have “cut the cord” to become totally wireless or replaced the ILEC cord by becoming a cable telephony customer. Only 37 percent of residential telephone users subscribe to the ILECs’ switched access services nationally, down from nearly universal status 20 years ago. The trend continues. According to a recent FCC report, “Over the three-year period [2013-2016], interconnected VoIP subscriptions increased at a compound annual growth rate of 10 percent, mobile voice subscriptions increased at a compound annual growth rate of 3 percent, and retail switched access lines declined at 11 percent per year.” As of the end of 2016, 51 percent of households nationally have no landline service whatsoever (i.e., no ILEC, CLEC, or cable telephony) and use their cell phones exclusively.

The demand for broadband services, on the other hand, has exploded. In Pennsylvania, based on the most recent FCC data, 94 percent of the population has access to fixed 25/3 Mbps

(down/up) service.⁸⁰ Thirty four percent of the state’s population subscribes at this speed. The wireless carriers are marketing LTE service speeds of between 12-20 Mbps. Nationally, 47 percent of the population have access to these higher speeds, while 99 percent have access to some form of wireless broadband with capacity of 10/1 Mbps or less.

Historically, basic local telephone service pricing has been guided by a desire to achieve and maintain universal service (i.e., making low cost telephone service available to everyone). Toll calling revenues (long-distance charges) and associated inter-carrier access charges, equipment rentals, and special services were long considered sources of revenue to provide a subsidy for basic local service rates. Business local rates were also priced higher to support residential rates. However, technology, competition, and regulatory choices have all but eroded the ability and desire of these revenue streams to provide local rate subsidies. The Pennsylvania Universal Service Fund and the federal Connect America Fund both provide some level of support to local service carriers, particularly those operating in rural, expensive-to-serve areas that retain a carrier of last resort obligation.

B. The Pennsylvania Public Utility Commission

1. Legal Powers

The Pennsylvania Public Utility Commission is an independent administrative agency comprised of 5 members appointed by the Governor for staggered 5-year terms and subject to confirmation by a majority vote of the Pennsylvania Senate.⁸¹

The Commission’s predecessor, the Public Service Commission (PSC), was created by the Public Service Company Law of 1913⁸² to replace the chaotic amalgam of legislative and local regulation then in place. The PSC was reorganized in 1937 to better “supervise and regulate” all public utilities doing business in the Commonwealth.⁸³ Its name was changed to the

⁸⁰ The figure is much lower in Pennsylvania’s rural areas – 20 percent.
https://apps.fcc.gov/edocs_public/attachmatch/FCC-16-6A1.pdf.

⁸¹ Information about the PUC, including copies of documents filed with and produced by the Commission; audio and videos of Commission proceedings; and forms, applications, and summaries of public meetings is available at the PUC’s [website](#). The Commission maintains a social media presence through Facebook ([Pennsylvania Public Utility Commission](#)) and Twitter ([@PA_PUC](#)).

⁸² Act of July 26, 1913, P.L. 1374. The Google Books project has a scanned copy of the original 1913 enabling legislation, which is available online at <https://books.google.com/books?id=VVAbAAAAYAAJ&hl=en>.

⁸³ Act of March 31, 1937, P.L. 160.

Public Utility Commission and its membership reduced from 7 to 5 members.⁸⁴ A companion law, known as the Public Utility Law, reformulated the basic laws governing public utilities.⁸⁵ These two companion statutes were amended several times in the ensuing years. The first major structural and procedural changes since the 1937 laws were made in 1976, following an extensive legislative investigation of the Commission's functions.⁸⁶

All relevant laws dealing with public utilities and the Commission's regulation of them are codified in Title 66 of the Pennsylvania Consolidated Statutes.⁸⁷ The Public Utility Code is the primary source of the Commission's power and authority. In this Handbook, citations to Title 66 are preceded merely by the word "Code" (e.g., "Code § 1301") rather than the more formal 66 Pa. C.S. § 1301 or 66 Pa. C.S.A. § 1301.

Title 52 of the Pennsylvania Code⁸⁸ is the secondary source of legal authority.⁸⁹ These are the Commission's regulations interpreting and implementing the statutory framework of the Code. Title 52 provides special rules of administrative practice and procedure before the Commission and further details special rules and regulations that public utilities and the public must follow. Additional rules and regulations are established by the Commission from time to time.⁹⁰ These must first be published in the Pennsylvania Bulletin, the official gazette of the Commonwealth.⁹¹ To avoid confusion between the Public Utility Code and the Pennsylvania Code; the latter will be referred to as "Regs." (e.g., Regs. § 52.53) instead of the more formal citation of "52 Pa. Code § 52.53."

⁸⁴ A more detailed history, compiled on the occasion of the Commission's 75th anniversary, can be found at the following link: http://www.puc.state.pa.us/about_puc/history.aspx.

⁸⁵ Act of May 28, 1937, P.L. 1053.

⁸⁶ Act of Oct. 7, 1976, P.L. 1057, No. 215 (amending the Public Utility Law) and the Act of Oct. 7, 1976, P.L. 1075, No. 216 (amending the law creating the Public Utility Commission).

⁸⁷ <http://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66>.

⁸⁸ The Pennsylvania Code is a compendium of rules and regulations of the various Commonwealth administrative agencies. Title 1 Pa. Code 31.1 *et seq.* provides general rules of administrative practice and procedure for all Commonwealth administrative agencies. It is applicable to the Commission except where a statute otherwise provides or where the Commission has promulgated different rules in Title 52. The Commission created an extensive procedural set of rules in 1984 and undertook extensive rewrites in 1997 and 2006, and thus 52 Pa. Code is very extensive and self-contained. There is little or no reliance by the Commission on 1 Pa. Code anymore.

⁸⁹ The Commission's regulations are online at: <http://www.pacode.com/secure/data/052/052toc.html>.

⁹⁰ Code § 501(b). Subject to the requirements of the Regulatory Review Act. <http://www.irrc.state.pa.us/>.

⁹¹ <http://www.pabulletin.com/index.asp>. The Bulletin is cited by volume and page number (e.g., 3 Pa. B. 801).

2. Administrative Description

The supervision and regulation of public utilities by the Commission includes: (1) establishing just and reasonable rates; (2) providing for adequate, efficient, safe service and facilities; (3) conducting audits, inspections, and investigations; (4) developing energy forecasts, plans, and conservation guidelines; (5) providing consumer services; and (6) ensuring compliance with the Public Utility Code and Commission rules and regulations.

The PUC oversees nearly 8,000 entities furnishing the following in-state services: electricity; natural gas; telephone; water and wastewater collection and disposal; steam heat; transportation of passengers and property by motor coach, truck, taxicab, and transportation network companies (TNCs); pipeline transmission of natural gas and hazardous materials; and public highway-railroad crossings.

To assure that the utility's management decisions take the public interest into account, the Commission must authorize the transfer of utility property, register issues of stocks and bonds, approve affiliated interest agreements, and, in some cases, approve construction or extension of facilities. The Commission requires utilities to use a uniform accounting system and to file various annual reports. These reports are open to the public for inspection, except where proprietary.

The Commission's major legal duty is to secure adequate services at reasonable rates for utility customers.⁹² The PUC acts in both a judicial and legislative capacity. Like a court, it takes testimony, resolves disputes by issuing decisions and orders, and subpoenas witnesses or records. It is also a policy-making agency that regulates markets and utility behavior by rulemaking. In maintaining scrutiny over utility service and facilities, the PUC is particularly concerned with the safety and reliability of electric, natural gas, water, and telephone facilities and railroad grade crossings. Utilities must report accidents to the Commission.

The PUC currently maintains a complement of 503 employees, including attorneys, rate and service analysts, auditors, economists, engineers, motor transit and railroad specialists,

⁹² "Mission Statement: The Pennsylvania Public Utility Commission balances the needs of consumers and utilities; ensures safe and reliable utility service at reasonable rates; protects the public interest; educates consumers to make independent and informed utility choices; furthers economic development; and fosters new technologies and competitive markets in an environmentally sound manner." http://www.puc.state.pa.us/about_puc.aspx.

communications specialists, safety inspectors, and enforcement investigators. They work, together with administrative, fiscal, computer, and clerical personnel, in bureaus that report to an Executive Director.⁹³ The PUC maintains 12 offices with a headquarters in Harrisburg. Regional offices operate in Altoona, Philadelphia, Pittsburgh and Scranton, serving as administrative coordinating points for enforcement officers and administrative law judges. The Philadelphia office also houses employees from the PUC's Bureau of Consumer Services (BCS).⁹⁴

To further its responsiveness to the public, the Commission has formed consumer and utility advisory councils, established an Office of Intergovernmental Affairs, and operates an Office of Communications. The latter is accountable for Commission media relations, employee communications and consumer education, in addition to acting as the lead staff for the Consumer Advisory Council.

BCS was established to make consumers aware of their rights and responsibilities, to provide timely procedural information, and to speed efforts to settle customer-utility disputes informally, avoiding the cost and delay of formal litigation. If customers have complaints about a utility, they may seek help by calling the PUC's toll-free number at 1-800-692-7380. Trained PUC customer service representatives help to address billing and quality of service issues, establish payment plans, or restore service.

The Commission is mostly funded by assessment of regulated public utilities. Subject to budgetary approval by the full Legislature and the Governor, the PUC may assess utilities up to three-tenths of one percent of the gross intrastate operating revenues of the utilities to cover the cost of regulation. All assessments are paid into a special fund maintained by the State Treasury for use solely by the Commission. The budget for Fiscal Year 2016-17 is \$71,947,000 in state funds and \$2,681,000 in federal funds, for a total of \$74,628,000. Each utility is billed in advance by the Commission for its share of an approved estimate of expenditures for the following fiscal year. The utilities pass these assessments on to their customers as a cost of doing business. Therefore, utility ratepayers ultimately pay for the Commission's operation.⁹⁵

⁹³ The bureaus are statutorily established. Code §§ 304, 305 and 308.

⁹⁴ Learn more about the bureaus and offices of the PUC here:
http://www.puc.state.pa.us/about_puc/bureaus_and_offices.aspx

⁹⁵ The Office of Consumer Advocate and the Office of Small Business Advocate are similarly funded.

C. OCA and OSBA

1. Office of Consumer Advocate

The Office of Consumer Advocate (OCA)⁹⁶ was established in 1976 and charged with representing the interests of Pennsylvania utility consumers before the Commission and federal agencies.

Administratively, the OCA is part of the Office of Attorney General. OCA staff consists of the Consumer Advocate, approximately ten attorneys, and eleven support personnel. The OCA's budgetary appropriation for Fiscal Year 2016-17 was approximately \$5.5 million. The Consumer Advocate is appointed by the Attorney General with the approval of a majority of the Senate.

The OCA's advocacy is specifically intended to be in the consumer interest ("represent the interests of consumers"). Traditionally, the OCA has defined this mandate as representation of the residential consumer, as opposed to commercial or industrial customers. This stance becomes important in a rate case when the issue of a utility's rate structure is examined.

A large portion of the OCA's efforts are spent on the rate cases of major utilities. The OCA also will become involved in utility service complaints, rulemakings, legislation, and other cases before the Commission. The OCA has no decision-making authority *per se*, but rather advocates a point of view before the Commission. The OCA may appeal a PUC ruling to the Commonwealth Court and higher appellate authorities.

The OCA, as an exclusively utility issue-oriented agency, possesses a wealth of information and expertise on utility matters and PUC practice. While the Office of Consumer Advocate may be unable to directly represent a consumer in a complaint, it will assist. Through its consumer education outreach, website, social media, and toll-free call center, the OCA also seeks to ensure that consumers are informed regarding changes in their utility service.

⁹⁶ <http://www.oca.state.pa.us/>.

2. Office of Small Business Advocate

Created in 1988, the Pennsylvania Office of Small Business Advocate (OSBA) is an independent state agency which represents the interests of small business customers in regulated utility matters before the PUC, federal regulatory agencies, and in state and federal courts.⁹⁷

Small businesses needed representation in rate cases. As noted previously, the OCA focuses on the representation of residential ratepayers in rate structure disputes. Furthermore, large commercial and industrial customers frequently field their own attorneys and expert witnesses. In contrast, small business customers did not have—and could not afford—their own representation, and therefore often were perceived to receive a disproportionate share of rate increases. The legislature sought to level the playing field by creating the OSBA.

The OSBA’s budget appropriation for Fiscal Year 2015-16 was approximately \$1.4 million. The office consists of the Small Business Advocate, four attorneys and two administrative persons.

II. Basic Rate Case Procedures

A. Tariffs

A base rate case⁹⁸ is triggered by the filing of a proposed new tariff rates.⁹⁹ Tariffs are extensive, detailed legal documents in which all the utility’s rates and service rules¹⁰⁰ are spelled out and changed only upon the approval of the Commission. The utility must adhere to its effective tariff.¹⁰¹

⁹⁷ <http://www.osba.pa.gov/About/Pages/default.aspx>.

⁹⁸ The difference between a base rate and a rider or other “sliding scale rate” is discussed in Section III of this handbook.

⁹⁹ Code § 1308(a). Frequently, only portions of a tariff are changed by means of a tariff supplement. Regs §§ 53.3, 53.7.

¹⁰⁰ Tariffs are defined under Code § 102 as including not only rates and rate schedules, but also “rules, regulations and practices” of the utility. Similarly, the Commission’s regulations at § 53.25 specify that a tariff shall set forth “all rules and regulations” that apply generally to all classes of service.

¹⁰¹ Code §§ 1302 and 1303.

There are numerous reasons for the existence of tariffs, including:

- If compelled to service everybody, individual contract formation becomes problematic. A tariff solves this problem.
- A tariff is special legislation and has the effect of law, spelling out the utility's duties and the rights of customers.¹⁰²
- If price discrimination is unlawful and adherence to tariffs required, then there is the need to publish prices and specify service offered.
- Since utility services are essential, tariff language can serve to define the duties of a utility and limit damage claims associated with outages.¹⁰³

Before filing a new tariff that proposes higher rates, the utility's rate experts, attorneys, and management typically spend several months preparing the proposal. When filing the tariff, the utility must also file extensive data supporting the rate change, and, if the requested increase exceeds \$1 million in gross annual revenues, file the prepared testimony of expert witnesses.¹⁰⁴ If the requested increase does not exceed \$1 million and the Commission suspends the case, testimony is filed at a date set by the ALJ during the prehearing conference.

B. Rate Case Time Frames

Generally, proposed rates may not become effective until 60 days after the new tariff(s) and supporting data are filed with the Commission.¹⁰⁵ This period allows the Commission to investigate the filing and also the gives customers time to file complaints against the proposed rates. Accordingly, if new rates are filed on Sept. 1, 2017, for example, the soonest they may become effective would be Oct. 29, 2017.

There are two types of base rate cases: general and non-general. General rate cases are defined as "a tariff filing which affects more than 5% of the customers and amounts to in excess of 3% of the total gross annual intrastate operating revenues of the public utility."¹⁰⁶ Non-general filings are for lesser amounts or for tariff changes that do not include any changes in revenues.

¹⁰² *Stiteler v. Bell Tele. Co.*, 379 A.2d 339, 341 (Pa. Cmwlth. 1977) ("Tariffs filed with a state regulatory agency, such as the PUC, are not mere contracts but have the force of law and are binding on the consumer and the utility.")

¹⁰³ *Behrend v. Bell Tele. Co.*, 363 A.2d 1152, 1164 (Pa. Super. 1976) ("Tariffs lawfully established, including limitations of liability, have the effect of law and are binding on both utility and subscriber.")

¹⁰⁴ These are the so-called "filing requirements." See, Regs. §§ 53.21 - 53.26 and 53.51 - 53.55.

¹⁰⁵ Code § 1308(a); Regs. § 53.31.

¹⁰⁶ Code § 1308(d).

Nearly all tariff changes filed by utilities that seek an increase in base rate revenues are of the general type. General and non-general rate cases are subject to different Commission review and implementation timelines.

If the filing constitutes a general rate case, at the end of the initial 60 days, unless the Commission permits the proposed rates to go into effect at that time, the proposed rate increase is automatically suspended for up to seven additional months. This added time enables the Commission to continue its own investigation and to provide for public hearings before an administrative law judge to examine the various claims made by the utility.

If the Commission does not reach a decision at the end of the seven-month suspension period, the rates originally proposed by the utility in its proposed tariff(s) may be placed into effect.¹⁰⁷ If the Commission ultimately determines that the rates as filed are too high, the excess portion is refunded with interest at the residential mortgage rate.¹⁰⁸

Non-general rate cases are lesser increases, or involve changes to service rules without a change to base rate revenues, and procedurally follow Code § 1308(b). The PUC has the authority to suspend non-general rates for an additional 6 months (plus another 3 months) after expiration of the initial 60 days. Proposed non-general rates automatically go into effect at the end of the 60-day review period unless the Commission takes affirmative action to suspend them (or obtains an extension from the company).

C. Notice to Customers

Pursuant to the Code, any utility seeking a rate change must notify its customers of a proposed general rate case in 3 ways:

- (1) By posting in the utility's offices;

¹⁰⁷ Code § 1310 prohibits the establishment of “temporary rates” in a general rate case. Prior to the 1976 rewrite of the Code, the Commission often took 1 to 2 years to reach a decision and meanwhile would set temporary rates by granting part of the requested amount. When a final decision was made, the Commission usually granted more than the temporary rates but less than the total amount requested; the utility was permitted to collect the difference between the temporary rates and the final amount granted back to the time the temporary rates were set. This recoupment, although clearly permitted by law, was much criticized by the media, misunderstood by the public, and labeled “retroactive ratemaking.” These concerns led to the 1976 amendments creating the “general rate case” scheme in Code § 1308(d). The only remaining alternative is to grant a petition for extraordinary rate relief, but this is virtually never done because the statutory requirements are so strict. Code § 1308(e).

¹⁰⁸ Code § 1308(d) (beginning with the words “Before the expiration of...”).

- (2) By written or printed notice. A public utility shall notify its customers by a written or printed notice. The written or printed notice shall be mailed at least 61 days or hand delivered at least 60 days prior to the proposed effective date of the tariff, tariff supplement or tariff revision; and¹⁰⁹
- (3) By news release. On the date the rate increase is filed, a public utility shall distribute news releases containing a description of the proposed rate changes to the major newspapers, radio, and television stations serving the public utility's area.¹¹⁰

Additionally, the utility, pursuant to Reg. § 53.45(a), is required to notify the Commission 30 days in advance of the filing of its intention to request a general rate increase of more than \$1 million in gross revenues. This notice is proprietary and confidential, given to facilitate the Commission's work load planning.

D. Complaints by Customers

For persons opposing a company's rate increase proposal, there are several avenues to express disagreement to the Commission.

1. Filing a Formal Rate Complaint

The filing a formal rate complaint renders the filer a party to the litigation and provides the right to send, receive, and answer interrogatories, appear at evidentiary hearings, and provide testimony under oath regarding the issues raised.

Expect to participate in a legal trial-like proceeding in which the ALJ will gather evidence and then render a recommended decision.¹¹¹ This means that the complainant and the utility must present facts on issues raised in the complaint. Individuals or companies may file formal complaints. Individuals do not need a lawyer to file a formal complaint.¹¹²

¹⁰⁹ As an alternative, a utility may elect to give written notice by bill insert on a one-month billing cycle beginning the day the tariff is filed, subject to specified conditions. Regs. § 53.45(b)(4).

¹¹⁰ Regs. § 53.45. The form of notice is prescribed at Regs. § 53.45(b)(i).

¹¹¹ Formal complaint procedures are specified at Regs. § 5.21 *et seq.*

¹¹² However, companies must be represented by an attorney.

Try to file the complaint no later than 60 days after the utility's filing of the new tariff.¹¹³ If filed by overnight delivery, certified, or priority mail, the date of deposit is the date of filing, not the date it is physically received by the Commission. However, the formal complaint should reach the Commission's Secretary before the effective date of the new rates as stated in the utility's rate filing notice.

A complainant needs "standing" to complain.¹¹⁴ The party's interest in the case must be "direct, substantial, immediate and not remote."¹¹⁵ A customer (or a group of customers) of the utility should have no problem establishing an interest.

Formal "rate" complaint forms are available on the Commission's website.¹¹⁶ Once completely filled out and signed with an original dated signature, the form can be mailed or delivered to the Secretary who will process, docket, and serve the complaint on the company and the administrative law judge presiding over the rate case. It is also the complainant's responsibility to provide the Commission and the ALJ with any changes to in address or to where the documents should be mailed.

A formal complaint should set forth the following:

1. The name; mailing address; telephone number; and electronic mailing address, if applicable, of the complainant. If several people are filing a joint complaint, there is no need to have every complainant sign it. One of the group can sign for all. If the group is an organized association, an authorized officer of the association should sign.
2. The name of the utility complained against.
3. The PA PUC case number.
4. The type of utility service provided.
5. A statement of opposition to the company's proposed rate increase. In the case of proposed increased rates, the allegation that the proposed rates are not just and reasonable and violate Chapter 13 of the Code is sufficient.

¹¹³ See Regs. § 5.32. If filed after the matter is suspended, the complainant takes the record of the case as it is at the time of filing the complaint. If the rate case is not suspended and the complainant files after the rates go into effect, the complainant will have the burden of proof.

¹¹⁴ In law, standing is the ability of a party to demonstrate sufficient connection to and harm from the action challenged to support that party's participation in the case.

¹¹⁵ *William Penn Parking Garage, Inc. v. City of Pittsburgh*, 464 Pa. 168, 346 A.2d 269 (1975).

¹¹⁶ The form of a formal complaint in a rate case can be found here:
http://www.puc.state.pa.us/General/onlineforms/doc/Formal_Complaint_Proposed_Rate_Increase.docx.

6. A statement of the relief sought.
7. If the complainant is represented by an attorney, the attorney's name; mailing address; telephone number; and, if available, the electronic mailing address.

The complaint must also be accompanied by a verification executed in accordance with the Commission's regulations.¹¹⁷

These requirements may sound complicated, but they are only common-sense rules providing for the essentials so that the Commission can process the complaint and proceed to hearings in accordance with the constitutional and statutory requirements of due process of law.

2. Other Ways to Participate in a Proposed Rate Increase

The Commission's procedures also offer consumers other avenues to meaningfully participate without filing a formal complaint. Consumers may do any of the following:

- File comments about a utility's proposed rate increase by mailing a form to the PUC's Secretary's Bureau.¹¹⁸ This permits customers to participate without becoming an active party to the litigation.
- Participate in the affected territory's public input hearing scheduled by the Commission if it determines that substantial public interest in a rate proceeding has been shown.¹¹⁹
- File an *amicus* brief, as discussed later.

Although not considered a party to the case if participating in these less formal ways, the complainant's voice can be heard without the time, effort and cost associated with a formal complaint.

The Commission regularly sets "Public Input" hearings during a rate case. These are public gatherings, like a town hall meeting, before the presiding ALJ that allow customers to appear in person and voice their concerns or opposition to the rate proposal on the record. By doing so, the testimony becomes part of the evidentiary record in the proceeding and can be relied upon by the ALJ and the Commission in rendering a decision. These hearings are well publicized in local newspapers and held at dates, times, and locations for the convenience of the public affected by the rate proposal.

¹¹⁷ Regs. § 1.36.

¹¹⁸ The form of a comment in a rate case can be found here:
http://www.puc.pa.gov/general/onlineforms/pdf/Comment_Proposed_Rate_Increase_Form.pdf.

¹¹⁹ Regs. § 69.321(b).

Rate cases attract participation by many people. The Commission endeavors to permit participation by persons, groups, and businesses wishing to assume all the rights and duties of parties, as well as those who have insufficient interest or inadequate resources to assume full party status. This has been well stated by Judge Ruhlen:

Although it is easier to manage a proceeding if all persons comply with the same rules and procedures, there are obvious advantages in the agency's providing some less expensive and burdensome modes of participation than assuming full party status. Such provisions typically leave the Judge considerable discretion as to the scope of activity allowed. One possibility is to permit any person to appear, present evidence, and submit argument, either written or oral, but to cross-examine witnesses only with the consent of the Judge. The Judge should supervise such presentations and seek a reasonable limit to the number of witnesses. He should explain their rights to inexperienced and uninformed persons, and devise ways for them to introduce evidence or state their position with minimal disruption of orderly procedure. He may, for example, himself call such persons as witnesses and question them to develop the facts or their point of view. As discussed earlier, if several such persons or groups represent the same or similar interests, the Judge should attempt to persuade them to consolidate their presentation and, in some circumstances, he may require them to do so.

To save work and expense, the Judge may limit the required distribution of documents to those persons who have a direct interest in the pertinent issue subject, of course, to the right of any person to request any specific material. Interested persons or groups, with modest resources, may be permitted to file a limited number of copies of their exhibits in the public reference room of the agency instead of reproducing and mailing them to all the parties; or if the material is extremely brief, it may even be read at the hearing without prior delivery to the parties. Arrangements vary with each case, but the Judge should give each interested person as full and convenient an opportunity to participate as is consistent, with the rights of others and the efficient management of the proceeding.¹²⁰

3. Formal Complaint Process Overview

The following is a step-by-step overview of the steps and considerations to be contemplated in deciding whether to file a complaint against a proposed base rate increase, although the same instructions would basically apply a complaint about quality of service or a utility's existing rates.

¹²⁰ These comments and several that follow are taken from *Manual for Administrative Law Judges* by the Honorable Merritt Ruhlen.

Step 1 - File the complaint with the Secretary of the Commission by mail, such as overnight delivery, priority, first class, or e-filing through the Commission's e-filing system on its website.¹²¹ A copy need not be served on the utility—the Commission's Secretary will do this.

Step 2 - In base rate cases, the utility is not required to file an answer to the complaint.¹²² Although it is unlikely, the utility may file a motion to dismiss the complaint because it is not sufficiently clear for the utility to answer it intelligently. Another, more specific complaint may be filed if the original complaint is dismissed.

Step 3 - If the case does go to a hearing, an ALJ is assigned to the case. Parties are notified by mail of the "prehearing conference", a case management meeting at which the parties agree to hearing dates and set the ground rules of how the case will proceed. The ALJ will ask parties to submit a Prehearing Conference Memorandum that lays out concerns, issues, and witnesses that the party intends to call. If attendance is not possible, the party should inform the ALJ in writing. It is customary for the ALJ, after it becomes clear that some formal complainants will not be participating in the hearings, to remove those parties from the mailing list of notices, exchanges of documents, and other important communications.

Step 4 - At the hearing, individuals may represent themselves. Other parties (corporations, associations, similar organizations, and all persons who are not representing themselves) must be represented by attorneys at law. The Commission's Rules of Practice and Procedure found at Regs Chapters 1, 3, and 5—particularly Chapter 5 (Formal Proceedings)—contain the Commission's regulations regarding process and hearings.

Step 5 - At the end of the hearings, the parties file main briefs and then, in response to each other, file reply briefs, after which the ALJ will enter a Recommended Decision, which will be served (mailed to the parties) by the Commission's secretary.

¹²¹ <https://www.puc.state.pa.us/efiling/eFileFAQs.aspx>. Note that this is not the same as filing by email message.

¹²² Regs. § 5.61(d).

Step 6 - After the ALJ decision is circulated, the Parties then file exceptions and reply exceptions addressing their support or disagreement with the ALJ's Recommended Decision. Thereafter, the Commission will decide the case at a Public Meeting.

Of course, the case could settle at any juncture. It is the Commission's policy to encourage settlements. In most cases, the parties work diligently to find common grounds upon which to settle the case in whole or part. The Commission's mediation process is available to the parties. If not, all parties settle, hearings, briefs, and exceptions will still be required.

4. Complaints by the Commission

The Commission itself is given broad authority to initiate an investigation of proposed rates by its own complaint. The burden of proof is always on the public utility in an investigation begun by the Commission involving rates. The Commission will consolidate, for purposes of hearing and decision, all private complaints pertaining to the new rates with the Commission's investigation.

If the utility's request is a large one, the Commission invariably will suspend and investigate the request, consolidating all complaints into one proceeding. If the utility is a small one, the Commission usually checks on the level of interest registered by the utility's customers.

E. Burden of Proof

Burden of proof refers to the responsibility of a party to present sufficient evidence into the formal record to prevail. Ratemaking is a civil proceeding, and therefore the burden of proof must meet the "preponderance of the evidence" test rather than the higher criminal test of "beyond a reasonable doubt." The concept may sound arcane, but it is a very important legal construct because it determines which party must go first in the presentation of evidence and who, ultimately, must be the most convincing.

Regarding rate proceedings, it is important to distinguish between proposed rates (i.e., when a utility files for a rate increase) and existing rates (i.e., rates contained in already approved tariffs). If the Commission on its own motion questions the justness and reasonableness of any rate, the utility has the burden of proving that the rate is just and reasonable under both

circumstances.¹²³ If anyone other than the Commission complains about a rate, the utility has the burden of proof only if the rate is a proposed one. If the rate is an existing rate (i.e., Commission-made), the complainant has the burden of proof.¹²⁴

There is one exception, however. The burden may rest with the utility where the proceeding involves the alleged violation of a prior determination or order of the Commission (e.g., where the utility fails to charge its existing tariffed rates).¹²⁵

F. Public Access to Commission Documents

To better understand the course of a rate proceeding, especially to participate in it, a complainant may wish to obtain certain information from the Commission's files. The most likely sources are discussed below. Most information is available; however, some must be kept confidential.

Supporting Data filed with the proposed tariff(s). This is the most fruitful information in any rate case, and it is available for public inspection, except certain data that the utility has protected by order of the Commission (e.g., market studies that would benefit competitors, if they knew). As previously discussed, the Commission's filing requirements provide that a great deal of information be supplied in support of the request for higher rates.

Annual Reports. Every utility is required to annually file a detailed report on its financial condition.¹²⁶

Dockets & Files. The Commission, since its inception in 1913, has maintained files on all formal proceedings before it. These files are divided into folders, and each folder is labeled with the docket number of the case.¹²⁷ Document and Testimony Folders are available

¹²³ Code § 315(a).

¹²⁴ Code § 332(a).

¹²⁵ Code § 315(b).

¹²⁶ Regs. §§ 57.47 (Electric), 59.48 (Gas), 65.19 (Water) and 63.36 (Telephone).

¹²⁷ Since 1977, the Commission has maintained hard copy case folders according to the following organization: a Testimony Folder (contains hearing transcripts and exhibits, depositions, responses to interrogatories, admissions, and all other information, not otherwise confidential); a Document Folder (complaints, petitions, answers, replies, motions, briefs, and requests for procedural or interim orders); and a Report Folder (contains staff reports, investigative materials, and all other confidential materials). Confidential data is kept off the Commission's website.

for inspection in the Commission’s file room (Commonwealth Keystone Building – 2nd Floor, 400 North Street, Harrisburg, PA 17120) during normal Commission business hours.¹²⁸

Commission Website at www.puc.pa.gov. The Commission offers a host of case-specific information on its website. There are two ways to search: 1) by docket number or 2) by using the Utility/Authority search tool.

- 1) On the opening page of the Commission’s website is “Search for Documents.” Click on that and the next page will allow you to type in a docket number (e.g., R-2017-1234567). Then scroll down and hit “Search.” All public documents associated with that docket number will appear, and they can be sorted by date or other criteria.
- 2) On the opening page of the Commission’s website is “All About PUC” in the banner across the screen. Click it and down the left-hand side of the next screen is “Utility/Authority Search.” Click on that and the next screen will display two boxes. The first box, “Search for Utilities by,” will allow you to type in the name of a utility the Commission regulates and then hit search. If the utility is regulated or licensed by the Commission, the name of the utility will appear below with the company’s utility code. Click that code and all public information about that utility will appear, including current and past docket numbers. You can then search each docket number by clicking on that case. The second box, “Search for Authorities by,” allows you to search by “Authority Service Type.” Use the down arrow to select the industry type, and all utilities matching that type regulated by the Commission will appear below. You can then search each utility individually.

Audits and Statements. The Commission’s Bureau of Audits¹²⁹ examines various aspects of utility operations. An adjustment clause audit verifies the energy costs incurred by a utility, determining if the utility overbilled or underbilled customers for yearly energy charges. Financial audits cover a wide variety of financial issues, including property records. Management audits are performed to determine the extent to which a utility has contained costs, developed reasonable long-range and short-range plans for its continued operation and maintenance, provided proper service to customers, and provided proper management and organizational structure. Management efficiency investigations examine management effectiveness and the operating efficiency of the utilities and assess the utilities’

¹²⁸ Material contained in the Report Folders is not available for public inspection without the approval of the Commission.

¹²⁹ http://www.puc.state.pa.us/about_puc/bureau_of_audits.aspx.

progress in implementing recommendations from prior management audits. Some of the publicly released audits are available on the Commission’s search page.

BCS Records. The Commission’s Bureau of Consumer Services maintains records of communications with complainants, utilities, and other persons regarding informal complaints against utilities. All statistical information routinely compiled by the bureau that does not identify a complainant is available to the public. For example, BCS publishes a “Consumer Service Performance Report” every year.¹³⁰

G. Analysis by Commission

1. Commission Trifurcation

To preclude the intermingling of the Commission’s prosecutorial and adjudicatory functions,¹³¹ as well as maintain impartiality and avoid *ex parte* communications,¹³² the Commission operates under a three-branch staffing system (prosecutorial, advisory, and adjudicatory) for the processing of formal cases:

- The Bureau of Technical Utility Services (**TUS**) serves as the advisory bureau to the Commission regarding fixed and transportation utility regulatory matters. In the case of general rate cases, the bureau performs the initial analysis of the rate filing and makes a recommendation as to whether to suspend, approve, or issue an option order. This is TUS’ only involvement in a contested base rate case.¹³³
- The Bureau of Investigation and Enforcement (**BI&E**), the Commission’s prosecutorial arm, employs lawyers and technical staff that routinely enter every suspended base rate case representing “the public interest.” They file testimony, cross examine company witnesses, file briefs and exceptions, and perform all other litigation functions.¹³⁴
- Office of Administrative Law Judges (**ALJs**)¹³⁵ preside at formal hearings in contested matters as an impartial hearing officer. The ALJ presides over the hearing and

¹³⁰ http://www.puc.state.pa.us/filing_resources/customer_service_performance_reports.aspx.

¹³¹ As required under Pennsylvania law. See *Lyness v. State Board of Medicine*, 605 A.2d 1204 (Pa. 1992); Code § 308.2(b).

¹³² *Ex parte* is defined in the Code as “any off-the-record communications to or by any member of the commission, administrative law judge, or employee of the commission, regarding the merits or any fact in issue of any matter pending before the commission in any contested on-the-record proceeding.” Code § 334(c). This prohibition is unlike other agencies that have a “permit, but disclose” policy toward such communications.

¹³³ Except in reviewing the final tariff.

¹³⁴ As compared to the OCA’s enabling charter of representing the “consumer interest.” The “public interest” is obviously a broader charge.

¹³⁵ OALJ is statutorily created. Code § 304.

development of the record, prepares a written decision outlining the issues, and recommends resolution of the disputed issues. The OALJ includes a mediation unit. In a suspended base rate case, the ALJ issues a Recommended Decision for Commission review.

- The Office of Special Assistants (**OSA**) advisory staff reviews the ALJ's Recommended Decision, as well as the parties' briefs and exceptions, and prepares a draft final order for the Commission's consideration; or, it may draft polling sheets for a vote on all outstanding issues.

- The **Commissioners** review the OSA draft order, as well as the underlying record, and publicly vote on the case. The final order that is issued reflects that vote.

ALJs almost always hear the case, but this is not required. The Commission itself (or one or more commissioners) may hear a case and issue a tentative decision, subject to exceptions and review by the full Commission.¹³⁶ Because of the volume of rate cases and the crush of other business, the commissioners themselves rarely participate in the evidentiary hearings of a case (except, perhaps, for public input hearings). Also, because of the sheer volume of data filed with a rate request, it is far more efficient for the commissioners to await a "boiling down" of the evidence into manageable form by the ALJ and OSA.

2. Initial Review of the Filing

When a base rate increase is requested, the Commission has three basic options:

- (1) Allow the proposed increase to become effective in the amount requested (in general rate requests, this must be done by affirmative order);
- (2) Permit a specified lesser increase (the option procedure); or
- (3) Suspend and investigate the request with the ultimate result being that all, some, or none of the request is approved.

Major rate cases (proposed increase in revenues exceeding \$1,000,000) receive only preliminary analysis by TUS during the initial 60-day period, basically to make sure that all necessary data has been submitted.¹³⁷ This abbreviated analysis is sent to the commissioners, who invariably agree to suspend and assign the case to an ALJ for hearing and a recommended decision. General rate increases of less than \$1,000,000 file lesser detail as required under Regs §

¹³⁶ Code § 331(c).

¹³⁷ Utilities filing for general rate increases exceeding \$1,000,000 in gross revenues must provide the Commission with extensive data before the filing will be accepted. Regs. 52 § 53.53. If the Commission does not notify the company of a defect within 30 days of filing a rate case, the filing is deemed perfected.

53.52 and receive an initial TUS staff review. The TUS report may recommend suspension, approval as filed, or an offer to accept a lesser amount.

3. Option Orders

Particularly in the case of rate increase requests by small companies, the Commission frequently offers the company the “option” of taking a lesser amount than requested without going through full rate case litigation. The filing is thoroughly reviewed by TUS within the initial 60-day review period, and ratemaking adjustments are usually made that result in a lesser amount than requested. A report and proposed order is then prepared for the commissioners’ review. Occasionally, the staff will report that “the Supplement does not appear to be unfairly discriminatory, unjust, unreasonable, unlawful, or detrimental to the rights and interests of the public; nor does it appear to produce an excessive return” and will therefore recommend that the request be granted in full. Even if the amount requested appears justified, the staff will occasionally recommend certain changes in the rate structure.

Most often, however, the staff will recommend something less than the requested amount. Appendix A to the order sets a level of increase that the Commission will allow without suspension. The following ordering paragraphs are then entered (general rate increase):

IT IS ORDERED:

1. That if, on or before ten (10) days after the date of entry of this Order, Typical Utility files a revised Supplement No. 1 to Tariff Water - Pa. P.U.C. No. 1 incorporating the schedule of rates shown on Attachment A, attached hereto, the proposed rates (as revised) are permitted to become effective September 1, 2017.
2. That if Typical Utility has not filed a revised tariff supplement as described in Ordering Paragraph No. 1 above on or before ten (10) days of entry of this Order, or has been granted additional time to do so by order of the Commission, the following shall apply:
 - Supplement No. 1 to Tariff Water - Pa. P.U.C. No. 1 shall be deemed suspended until March 31, 2018, unless otherwise directed by order of the Commission.
 - An investigation is instituted to determine the lawfulness, justness, and reasonableness of the rates, rules, and regulations contained in the proposed Supplement No. 9 to Tariff Water-Pa. P.U.C. No. 1.
 - Said investigation shall be assigned to the Office of Administrative Law Judge for an Alternative Dispute Resolution, if possible, or the prompt scheduling of such hearings as may be necessary culminating in the issuance of a Recommended Decision.

3. That a copy of this Order shall be served upon the Respondent, the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, the Office of Small Business Advocate, and the Office of Administrative Law Judge.

BY THE COMMISSION

The utility then must decide whether to take the lesser amount that appears in Attachment A or have its request sent to an ALJ for the statutory seven-month suspension period. If the company elects to accept the option, it files a new tariff (e.g., Supplement No. 10) within 10 days of the option order consistent with Attachment A. This new tariff is reviewed by TUS as to whether it complies with the option order.

The option process is a good thing. Frankly, the Commission would be overwhelmed if it could not expeditiously dispose of some of the many small company rate increase requests made each year. Not only would full litigation be inefficient, but it would be unnecessary. The Commission's staff is familiar with the operations and physical plant of the regulated companies. The Commission's files contain every rate request made by the company and a great deal of other information.

Option orders are never extended in the following circumstances:

- General rate cases of large size, with several interveners, or containing unusual issues;
- Where a complaint has been filed;¹³⁸
- When there is expressed opposition to the proposed increase by the general public;
- When lack of information prevents TUS from making a sound recommendation to the Commission; or
- When staff's investigation reveals that the utility is not entitled to any increase.

4. Suspension Orders

Where TUS recommends that the proposed increase be suspended, and the Commission agrees, the format of the order is as follows (general rate case):

IT IS ORDERED:

¹³⁸ See *Joseph Horne Co. v. Pa. P.U.C.*, 485 A.2d 1105 (Pa. 1984). The case held that the PUC established temporary rates in violation of the prohibition contained at Code § 1310(a) during a general rate increase request by approving a non-unanimous settlement where a non-settling party might, if successful, cause the settlement rates to be subsequently revised.

1. That an investigation on Commission motion be, and hereby is, instituted to determine the lawfulness, justness, and reasonableness of the rates, rules, and regulations contained in Typical Utility's proposed Supplement No. 1 to Tariff Water - Pa. P.U.C. No. 1.
2. That Typical Utility's proposed Supplement No. 1 to Tariff Water - Pa. P.U.C. No. 1 is suspended by operation of law until March 31, 2018, unless otherwise directed by Order of the Commission.
3. That within ten (10) days following the Order entry date, pursuant to 52 Pa. Code § 53.71, Typical Utility shall file (or e-file) tariff supplements with the Commission and post the tariff supplements at the office of Typical Utility to announce that the aforementioned supplements are suspended until March 31, 2018. Attached is a sample copy of a suspension supplement.
4. That this investigation shall include consideration of the lawfulness, justness, and reasonableness of the existing rates, rules, and regulations of the Typical Utility.
5. That the case be assigned to the Office of Administrative Law Judge for Alternative Dispute Resolution, if possible, for the prompt scheduling of such hearings as may be necessary culminating in the issuance of a recommended decision.
6. That a copy of this Order shall be served upon the Typical Utility, the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, the Office of Small Business Advocate, and any persons who have filed Formal Complaints against the proposed tariff of the Typical Utility.

BY THE COMMISSION

The case is now suspended for the seven-month statutory period and either settled or fully litigated (or some combination of the two).

4. Settlement of Formal Commission Cases

It is the policy of the Commission to encourage the settlement of formal cases by the parties.¹³⁹ The Commission also offers mediation as a path to effective and efficient dispute resolution. Mediation is a voluntary, confidential, and non-binding process through which a neutral Commission employee, the mediator, assists the parties in reaching a mutually acceptable settlement of their disputes.¹⁴⁰ All parties must consent to mediation. The utility company filing for the rate increase must agree in writing to extend the statutory deadline by at least 60 days.¹⁴¹

¹³⁹ Regs. § 69.401.

¹⁴⁰ http://www.puc.state.pa.us/about_puc/mediation.aspx. See Regs. § 69.391.

¹⁴¹ Regs. § 69.392(d)(2).

At the prehearing conference, the ALJ likely will inquire as to the possibility of the parties settling the matters in issue. Parties will often build time into the litigation schedule for settlement conferences. A rate case may settle at any time during adjudication. Rate cases often settle following public input hearings and prior to evidentiary hearings or prior to when briefs are due.

Available to the parties, although it has not been used in rate cases, is a settlement judge process under the Commission's Policy Statement and Guidelines.¹⁴² When it is requested and the parties consent, the ALJ may participate in the settlement in a one-judge or two-judge system. In a one-judge system, the ALJ will be careful not to take such a strong position that he might thereby disqualify himself should a settlement not be achieved. In a two-judge system a second ALJ will be assigned to adjudicate the matter if no settlement is achieved.

Rate case settlements are in writing and can be very detailed and exacting, containing not just the new rates, but future actions to improve service or follow-up on items for future cases. Stay out provisions are routine.¹⁴³ Generally, complainants agree to withdraw or discontinue their complaints upon Commission approval of the settlement terms and preserve the right to withdraw from the settlement and renew the hearing if the Commission makes any changes to the settlement that the party might deem unacceptable.

The settlement agreement will append the new tariffs stipulated by the parties. Moreover, each party will prepare and submit an individual statement in support, explaining why they believe that the settlement is in the public interest and should be approved by the ALJ and Commission. Usually the parties agree that all pre-filed testimony and exhibits will be placed in the record without objection or the need for cross-examination.

When the ALJ approves a settlement agreement, a Recommended Decision will be issued for Commission review. The decision will include findings and information in sufficient detail to enable the Commission to make an independent judgment on the question of whether the settlement is in the public interest and thus should be approved. The settlement agreement and related documents, as well as the ALJ's Recommended Decision, will then go to the Commission for review. Often the settlement will stipulate that the new rates will become effective on or

¹⁴² Regs. § 69.405(c).

¹⁴³ Agreement not to file another base rate case for a specified period.

before a date certain (time is money after all), and the ALJ and Commission will accommodate the request if possible.

The ALJ will determine whether the settlement is lawful, just and reasonable, and in the public interest. The ALJ in a Recommended Decision may recommend approval of the settlement without modification, with modification(s), or that the settlement be rejected.

Given the complexity of rate cases, it not unusual to have a non-unanimous/all issues settlement, a unanimous/partial issues settlement, or even a non-unanimous/partial issues settlement. This is just the process of winnowing down the scope of the case and making it more manageable. Of course, a more limited remaining case is better for resolution.

Where not all issues are resolved in the settlement, the parties will usually agree to use the stipulated record and submit briefs on the unresolved issues. Where not all parties agree, the ALJ will provide the opportunity for the objecting party to set forth facts, affidavits, argument and relevant legal analysis, and, if desired, a specific request to continue to litigate. A request to litigate should be supported by appropriate information and legal argument concerning the implications of denial of a continued opportunity to litigate in lieu of settlement.¹⁴⁴

The ALJ's Recommended Decision then will be submitted for exceptions to all parties in the case, thus giving those non-settling parties a further opportunity, this time directed to the Commission itself, to indicate why they have not accepted the settlement and/or why the Commission should modify it.

H. Hearings before the ALJ

The purpose of hearings is the full development of the relevant facts and a sufficient record from which a decision may be written. The rules of evidence are adhered to with some relaxation on technical matters. There is no standardized model for a formal administrative hearing. The organization and form depend upon such factors as the type of case, the issues, the number of witnesses, custom, and the ALJ. The one common criterion is the development of a fair, clear, and concise record.

¹⁴⁴ Regs. § 69.406.

The formal administrative hearing possesses substantially the same formality, dignity, and order as a judicial proceeding. It moves as rapidly as possible, consistent with the essentials of fairness, impartiality, and thoroughness.

1. Appearances

An individual may appear on his or her own behalf. All other parties must be represented by an attorney at law, unless the Commission otherwise permits.¹⁴⁵ An attorney who signs an initial pleading in a representative capacity shall be considered to have entered an appearance in that proceeding.¹⁴⁶ Otherwise, an attorney files a notice of appearance.¹⁴⁷

2. Consolidation of Hearings

Proceedings involving a common question of law or fact may be consolidated for hearings and disposition by the Commission or an ALJ.¹⁴⁸ For instance, a Commission investigation of proposed rates and complaints relating to those rates is usually consolidated for hearings and decision.

3. Authority of the ALJ

An administrative law judge has the authority to administer oaths and affirmations; issue subpoenas authorized by law; rule on motions and evidentiary questions; regulate the course of the proceeding; dispose of procedural requests or similar matters; render Initial and Recommended Decisions, subject to Commission approval; and to take any other action authorized by the Commission consistent with the Public Utility Code.¹⁴⁹

It is the ALJ's responsibility to ensure the development of a sound and sufficient factual record. He or she may: call attention to gaps in the evidence; insist that additional witnesses be called to testify upon essential matters not covered by the parties; direct the parties, either on oral argument or by brief, to discuss any issues or points considered germane; and direct the parties to

¹⁴⁵ Regs. §§ 1.21 and 1.22.

¹⁴⁶ Regs. § 1.24.

¹⁴⁷ Regs. §§ 1.24 and 1.25.

¹⁴⁸ Regs. § 5.81.

¹⁴⁹ Code § 331.

research a question of law or policy at any time. The ALJ, however, must not act as an advocate for any party.

4. Public Input Hearings

The Commission routinely schedules public input hearings in general rate cases at convenient hours within the utility's service territory for the public to attend and testify.¹⁵⁰ The Commission has been also trialing "Smart Hearing" that enable consumers to participate via live streaming on the PUC's website. During Smart Hearings, concerned individuals can offer their comments by telephone and be included in the live internet stream. In addition to the public, the utility, BI&E, OCA, OSBA and potentially other parties attend these hearings. The ALJ presides.

Persons wishing to testify will be presented with two options:

- (1) To testify formally in the case, upon oath or affirmation, and be subject to cross-examination.
- (2) To make unsworn or unaffirmed statements at the hearing. These statements are "off-the-record". They will not be subject to cross-examination, will not be transcribed by the court stenographer, and will not be considered by the presiding officer in the recommended decision.¹⁵¹

On-the-record testimony, to the extent it is relevant, material, and competent, will be considered as evidence by the presiding officer and the Commission subject to the customary rules of procedure and evidence.¹⁵² Evidence not "on the record" cannot be considered by the Commission in deciding the case. Only a decision based on "substantial evidence on the record" will be upheld by an appellate court if the decision is appealed.¹⁵³ Members of the public are encouraged to testify under oath, so the Commission can review and consider the public's views.

Persons may also choose not to testify at the public input hearing but rather provide information to BI&E, OCA, or OSBA for possible use by them in the hearings at their discretion.¹⁵⁴

¹⁵⁰ The Commission's policy on public input hearings is stated at Regs. § 69.321.

¹⁵¹ Regs. § 69.321(d).

¹⁵² Regs. § 69.321(e).

¹⁵³ *U.S. Steel Corp. v. Pa. P.U.C.*, 37 Pa. Cmwlth. 195, 390 A.2d 849 (1978). See also, *Blumenschein v. Pittsburgh Housing Authority*, 379 Pa. 566, 109 A.2d 331 (1954).

¹⁵⁴ Regs. § 69.321(d)(3).

5. Prehearing Conference

Code § 333 authorizes the presiding officer to hold one or more prehearing conferences during the course of the proceeding or on his own motion.¹⁵⁵

In the prehearing conference order sent by OALJ announcing the time and place of the prehearing conference, the parties will be instructed to prepare and circulate a “Prehearing Conference Memo” that identifies their issues, positions, witnesses, schedule of discovery, whether settlement discussions have taken place, and proposed written testimony filing and hearing dates, among other items. The parties will often huddle prior to the conference to see if they can agree to the schedule and other aspects of case management in advance.

The purposes to be served at such conferences include:¹⁵⁶

- Simplification of issues.
- Exchange of witness lists and exhibits.
- Stipulations (the parties agree on certain facts).
- Limitation of the number of witnesses.
- Provisions for discovery and production of data.
- Such other matters as may aid in expediting the orderly conduct and disposition of the proceeding.
- Discuss opportunities for settlement and settlement conferences.
- Scheduling of hearing dates.

The prehearing conference is a formal hearing and is transcribed. If the parties consented to mediation, an initial mediation session with an OALJ mediator is usually held following the initial prehearing conference.

6. Scheduling of Hearings

Hearing dates in rate proceedings, including a range of dates for public input hearings, are determined at the prehearing conference by the ALJ.¹⁵⁷ Rate cases “are to be given

¹⁵⁵ See Regs. § 5.223 (Authority of presiding officer at conferences).

¹⁵⁶ Code §333. Regs. §5.224.

¹⁵⁷ Regs. §§ 5.203 and 5.224.

preference over all other proceedings, and are to be decided as speedily as possible.”¹⁵⁸ The ALJ may continue a scheduled hearing upon his or her own motion or upon the request of a party for good cause shown. Mere convenience or other engagements of counsel will not ordinarily constitute grounds for continuance.¹⁵⁹

7. Discovery and Production of Data

Parties are authorized by the Code¹⁶⁰ and Commission regulations to “discover” virtually the entire case of every other party to the proceeding. Discovery is the process of obtaining evidence from other parties to the case.¹⁶¹ There is an entire subchapter in the Commission’s regulations on the topic of discovery.¹⁶²

Where hearings are opportunities for the parties to test the validity of the data and the credibility of the witnesses, discovery undertaken in advance of the hearing is a means to probe these areas and collect facts and exhibits that will be used on the record. Parties should initiate discovery as early in the proceedings as reasonably possible.

The Commission’s regulations provide that “a party may obtain discovery regarding any matter, not privileged, which is relevant to the subject matter involved in the pending action, whether it relates to the claim or defense of the party seeking discovery or to the claim or defense of another party, including the existence, description, nature, content, custody, condition, and location of any books, documents or other tangible things and the identity and location of persons having knowledge of a discoverable matter. It is not ground for objection that the information sought will be inadmissible at hearing if the information sought appears reasonably calculated to lead to the discovery of admissible evidence.”¹⁶³

Discovery or deposition is not permitted that:

- Is sought in bad faith.

¹⁵⁸ Code §315; Regs. §5.203(b).

¹⁵⁹ Regs. § 5.203(c).

¹⁶⁰ Code § 333.

¹⁶¹ The term “discovery” is literal: “...the ascertainment of that which was previously unknown; the disclosure or coming to light of what was previously hidden; the acquisition of notice or knowledge of given acts or facts...” <http://thelawdictionary.org/discovery/>.

¹⁶² Regs. § 5.321 – 5.373.

¹⁶³ Regs. § 5.321.

- Would cause unreasonable annoyance, embarrassment, oppression, burden, or expense to the deponent, a person, or party.
- Relates to a matter that is privileged.
- Would require the making of an unreasonable investigation by the deponent, a party, or a witness.¹⁶⁴

A discovery request that would require the compilation of information that the answering party does not maintain, or a special study is not objectionable, if the study or analysis cannot be reasonably conducted by the party making the request.¹⁶⁵

There are several methods of discovery recognized in Commission practice:

- **Interrogatories.**¹⁶⁶ This is the most common method of discovery. Written questions are served on a party that must be answered in writing under oath. Answers are due within 15 days, unless the ALJ establishes a different schedule. Objections to interrogatories are due in 10 days. An objection places the obligation on the party submitting the interrogatory to file a motion to compel within 10 days. The answering party is under an obligation to update any prior response upon discovering that the original response is incorrect or incomplete (applicable to all discovery). Interrogatories may ask for fact, opinion, or the production of documents.¹⁶⁷
- **Requests for documents, entry for inspection and other purposes.**¹⁶⁸ A party is entitled to inspect and copy designated documents or tangible things, and may request that the party against whom discovery is sought reproduce the designated documents at the requesting party's expense. The latter is the more common practice, and the utility almost never asks to be reimbursed.¹⁶⁹
- **Requests for admissions.**¹⁷⁰ To expedite matters, or, as the Code states, "to conserve hearing time,"¹⁷¹ a party can serve another party with a written request that certain facts be "admitted" (conceded as true), so that proof of the same will not have to be undertaken during hearings. A party may seek admissions "of any relevant, unprivileged, undisputed facts, the genuineness of any document described in the request, the admissibility of evidence, the order of proof and

¹⁶⁴ Regs. § 5.361(a).

¹⁶⁵ Regs. § 5.361(b).

¹⁶⁶ Regs. §§ 5.341 - 5.342.

¹⁶⁷ See discussion next of requests for documents, entry for inspection and other purposes.

¹⁶⁸ Regs. § 5.349.

¹⁶⁹ Because requests for documents are considered a separate discovery vehicle, parties frequently title the document as "Interrogatories and Requests for Production of Documents."

¹⁷⁰ Regs § 5.350.

¹⁷¹ Code § 333(e).

other similar matters.”¹⁷² Both answers (a detailed admission or denial) and objections, if any, are due within 20 days of the request. If neither are filed, the matter is deemed admitted.

- **Depositions.**¹⁷³ While not used very frequently before the Commission and never in a rate case, persons may be “deposed” - asked oral or written questions under oath. The deposed individual may be associated with a party, but that is not required. An application to take an oral deposition must be submitted to the ALJ.¹⁷⁴ If oral questions are posed, the questions and answers are transcribed. The resulting transcript usually is not introduced into evidence, but is used to learn information concerning the deposed party’s case and, sometimes, to cross-examine the same witness later should contradictory testimony be given in hearings.
- **On the record data requests.**¹⁷⁵ This is a discovery mechanism used at the hearing. During cross-examination, a witness may refer to a document or fact that is not of record and not previously produced. Or, the witness may not know the answer to a question. Under such circumstances, a party may request that a witness provide information or documents later. The request may be made orally or in writing at the time the witness appears for cross examination. Objections must be made at the time that the on-the-record data request is made. Answers are due within 10 days.

8. Subpoenas

An ALJ has the authority to issue subpoenas compelling attendance to testify (*ad testificandum*) or to produce documentary data (*duces tecum*) upon the request of a party.¹⁷⁶ The person subpoenaed need not be a party to the case. An objection to a request for subpoena is due within 10 days, and the ALJ must rule within the next 10 days. If a subpoena is not obeyed, Code § 3307 provides that “such person shall be guilty of a summary offense.”

9. Interlocutory Appeals

“Interlocutory” means something injected into the middle of a proceeding. The Code provides for an interlocutory appeal to the full Commission “on any material question arising in the course of a proceeding.”¹⁷⁷ Generally speaking, the Commission prefers to rule upon all of

¹⁷² Code § 333(e); See also Regs. § 5.350(a).

¹⁷³ Regs. §§ 5.343 – 5.348.

¹⁷⁴ Regs. § 5.344.

¹⁷⁵ Regs. § 5.351.

¹⁷⁶ Code § 333(j) and Regs. § 5.421.

¹⁷⁷ Code §§ 331(e) and 333(h).

the issues raised at the end of the case. Therefore, interlocutory review is generally limited to circumstances where it is necessary to “prevent substantial prejudice or to expedite the conduct of the proceedings.”¹⁷⁸ Interlocutory review of discovery disputes is not favored.¹⁷⁹

There are two basic mechanisms to transmit an interim dispute to the Commission for resolution:

- A petition for interlocutory Commission review and answer to a material question.¹⁸⁰ A party may seek interlocutory review by filing a request directed to the Commission (not the ALJ), not to exceed 3 pages, which states the question to be answered and why a response by the Commission is necessary. Briefs by the parties are due within 10 days and may not exceed 10 pages. Petitions that are not granted within 30 days of filing are deemed to be denied.
- Interlocutory review of a material question submitted by a presiding officer.¹⁸¹ The ALJ may certify a question to the Commission upon his or her own motion or upon motion of a party. Parties may brief the issue to the Commission (not to exceed 15 pages) within 7 days of service of the ALJ’s certification. Again, there is an automatic denial if the PUC does not act within 30 days.

An interlocutory appeal does not stay the matter unless directed by the ALJ.

10. Written Testimony

Direct testimony consists of the initial testimony and supporting exhibits produced by the witness. After a period for discovery the other parties then file their own direct testimony in response, the scheduling of which was established at the prehearing conference. The filing utility invariably find that rebuttal evidence is necessary in response to the parties’ direct testimony, and often the parties also file rebuttal testimony in response to each other. This is the rebuttal phase. It is not unusual for parties to also want to present surrebuttal testimony as an opportunity to reply to the others’ rebuttal testimony.¹⁸² Finally, the utility frequently preserves the last word

¹⁷⁸ Regs. § 5.302(a).

¹⁷⁹ Code § 333(h) Where the ALJ’s “ruling involves an important question of law or policy which should be resolved at that time.”; Regs. § 5.304 “... when the ruling involves an important question of law or policy that should be resolved immediately by the Commission.”

¹⁸⁰ Regs. §§ 5.302 and 5.303.

¹⁸¹ Regs. § 5.305.

¹⁸² So that by the rejoinder phase, the utility’s argument is—I was right in my direct testimony, you were wrong to say in your responsive direct testimony that the arguments made in my direct testimony were wrong, and I told you so in my rebuttal. Now having listened to the arguments raised in your surrebuttal about why my rebuttal was inaccurate, you are still wrong for the following reasons. For opposing parties, it’s just the reverse.

by delivering oral rejoinder testimony.¹⁸³ The entire process is one of issue reduction, so that the material contained in rebuttal may only address issues and arguments raised in direct, and surrebuttal is limited to what is raised in rebuttal.

The Commission generally encourages the use of written testimony in its more complex proceedings,¹⁸⁴ and “[w]ritten direct testimony is required of expert witnesses testifying in rate cases.”¹⁸⁵ All relevant facts and opinions should be included in the party’s direct testimony to the extent possible and known.

Commission regulations specify that initial utility direct testimony shall be provided as part of any initial tariff filing seeking a general rate increase in excess of \$1 million.

The testimony of the filing utility shall include a complete explanation and justification of claims which depart from the unadjusted test year results of operations, including the methodology and rationale. The testimony shall be accompanied by supporting worksheets, if necessary, and shall refer to supporting exhibits to which the testimony relates. The explanation and documentation of the proposed adjustments shall enable a reasonably informed party to determine how the amount was calculated and to understand why the amount is being claimed.¹⁸⁶

There are definite advantages to using pre-filed, written testimony:

- Offers an accurate, irrefutable record of a party’s position.
- Avoids surprises on the day of the hearing.
- Provides a good basis for submitting interrogatories on the witness.
- Allows responding parties to better prepare their rebuttal.
- Limits the hearing time used for hearing.
- The expert witness and counsel can collaborate not only on the answers to be given but the questions to be asked.

¹⁸³ “In a proceeding, the party having the burden of proof, shall open and close unless otherwise directed by the presiding officer... Oral rejoinder, if proposed by the party with the burden of proof, shall be completed before any cross-examination of the witness is conducted.” Regs. § 5.242(a).

¹⁸⁴ The Public Utility Code provides that “[t]he commission may, by rule, adopt procedures for the submission of all or part of the evidence in written form.” Code § 332(c).

¹⁸⁵ “Written testimony must normally be prepared in question and answer form, include a statement of the qualifications of the witness and be accompanied by exhibits to which it relates. A party offering prepared written testimony shall insert line numbers in the left-hand margin on each page. A party should also use a logical and sequential numbering system to identify the written testimony of individual witnesses.” Regs. § 5.412(a).

¹⁸⁶ Regs. § 53.53.

- The use of prepared testimony, circulated in advance, also affords opposing counsel and parties a greater opportunity to prepare for cross-examination.

11. Protective Orders

Often facts disclosed or discovered in a rate case are considered by the disclosing party to be confidential, usually for competitive reasons (e.g., business research, strategy, forecasts, etc.). Commission regulations allow for a limitation on the disclosure of trade secrets or other confidential information on the public record “when a party demonstrates that the potential harm to the party of providing the information would be substantial and that the harm to the party if the information is disclosed without restriction outweighs the public’s interest in free and open access to the administrative hearing process.”¹⁸⁷

Procedure requires the party claiming proprietary status to file a petition for protective order. However, since protection is so routine, given the competitive overlap in many regulated industries, the parties often render an agreement and submit it to the ALJ for approval.¹⁸⁸

Protective orders/agreements typically require the disclosing party to mark the document(s) for which protection is sought as proprietary. Adverse parties may subsequently challenge that designation, and the disclosing party usually retains the burden to demonstrate why the confidential designation is appropriate. Typical restrictions limit the use of the information to that proceeding and to attorneys and experts in that case who have no financial conflict of interest. The order/agreement may require that the parties receiving the information return the information and the copies thereof to the party after the proceeding.

The Commission’s practice is to allow the lawyers and experts, who agree to maintain confidentiality under protective order or agreement, to review the document. Confidential information is excluded from the public record, placed in a physically separate folder, and is not available at the Commission’s website. For purposes of the evidentiary record, testimony and exhibits that contain confidential information are marked as such, and a proprietary section of the transcript is set aside in a sealed folder.

¹⁸⁷ Regs. § 5.365(a); See also, Code § §333(i).

¹⁸⁸ The party claiming the privilege has the obligation to seek protection. Reg. § 5.365(c)(4).

12. Testimony Transcribed

Hearings are stenographically-transcribed and, together with the written testimony admitted in evidence, constitute the record. A copy of the testimony may be obtained by arrangement with the court reporter. The Commission cannot distribute free copies of the transcript (or allow others to photocopy the Commission's original transcript) under the service contracts with the various reporters.

13. Procedure at Hearing

The following discussion assumes that written testimony, all of the way through surrebuttal or rejoinder, has been exchanged by the parties in advance of the first evidentiary hearing.

a) Presentation and Admission of the Case

At the hearing, each party presents all of its testimony (direct, rebuttal, and surrebuttal) and exhibits to be marked for identification that constitutes its direct case. As the party with the burden of proof (burden of going forward and of persuasion), the utility goes first. Then it is the turn of the advocates (BI&E, OCA, OSBA) and any other parties in the case. Each party's witness is called in a predetermined sequence (the testimony is numbered in a sequence; e.g., Typical Utility Statement Nos. 1-6).

Every witness and every piece of testimony/exhibit goes through the same steps of identification and authentication (Step 1 is the ALJ; all others are questions asked by counsel and answered by the witness). The process is formulaic:

1. Sworn. "Do you solemnly swear (or affirm) that the testimony you are about to give is the truth; the whole truth, and nothing but the truth (so help you God)?"
2. Identification of witness. "Please state your name and position for the record."
3. Authentication of Testimony. "I show you a document titled Direct Testimony of Fred Flintstone, preliminarily marked as Typical Utility Direct Statement No. 1, to which there are appended 7 exhibits, Typical Utility Exhibits Nos. 1-7. Were these prepared by you or under your supervision?" (Yes). Counsel asks that the ALJ allow them to be so marked.
4. Corrections (if needed). "Are there any changes that you wish to make to the testimony and/or exhibits?" (Yes/No).
5. Authentication of Testimony and Exhibits. "Is the information contained in Typical Utility Direct Statement No. 1 and Typical Utility Exhibits Nos. 1-7 (as

corrected) true and correct to the best of your knowledge, information, and belief? (Yes).

6. Move into the record by counsel. “Your Honor, we ask that Typical Utility Direct Statement No. 1 and Typical Utility Exhibits Nos. 1-7 be entered into the record as if read, subject to any timely motion.”¹⁸⁹

Steps 3-6 are undertaken for all other testimony and exhibits that are sponsored by that witness. Once the admission process is complete, counsel offers the witness: “The witness is available for examination by the parties.”

Counsel may also decide to move the testimony/exhibits into the record after cross. There is considerable merit to considering motions to strike at the outset,¹⁹⁰ because it eliminates cross-examination on inadmissible evidence. Objectionable material, if admitted, frequently generates the most cross-examination. Additional motions to strike may be entertained later based on further developments at the hearing.

If a motion to strike is posed, the ALJ will note the objected material and the basis of objection. When all objections have been received and countervailing arguments made, the ALJ will rule, giving the reasons. The stricken material is lined (crossed) out, so that the original shows but has a line through it.¹⁹¹ This material is not a part of the record and is not considered by the Commission except to rule on the correctness of its exclusion. Stricken portions are indicated on the record copies.

b) Cross-examination

The ALJ will establish an order of cross-examination that will develop the most concise and clear record.¹⁹² This frequently cannot be determined until the direct evidence has been presented. Ordinarily priority is given to that party which will have the most extensive cross-examination or the greatest interest in the direct testimony.

¹⁸⁹ The ALJ is the only one in the room that can enter testimony and exhibits into the record, so make sure that you get that ruling from him or her.

¹⁹⁰ Another practice is to file a motion to strike in writing before the hearing to give the ALJ more time for thorough consideration.

¹⁹¹ “Pre-served testimony which was stricken at hearing shall be revised to reflect that which was stricken by containing hand-marked strikethroughs or electronic strikethroughs on the testimony.” Regs. § 5.412a.

¹⁹² “The presiding officer may direct the order of parties for purposes of cross-examination...” Regs. § 5.242. “In a rate proceeding, the presiding officer or the Commission will establish the schedule for the filing and authentication of written testimony, and for cross-examination by other parties.” Regs. § 5.412(d). The ALJ, in fact, has broad powers in the hearing room. See Regs. § 5.403.

Although styles may vary, the objective of cross-examination generally is: to diminish the credibility of the witness, show a lack of support for conclusions drawn by the expert, reveal contradictions in past and present testimony, and demonstrate alternative methods that should be considered. Cross-examination entails testing the basis for the witness' conclusions, challenging the factual accuracy and veracity of the exhibits, and exploring inconsistencies. The major refutation of expert opinion testimony should usually be supplied not by cross-examination but by submission prior to the hearing of testimony by the opponent's experts.

There are many expert treatises on how to conduct cross-examination, but the best approach is to keep the questions simple and the scope narrow. The classic advice is: "Don't ask the question, if you don't know the answer." The expert witness is both an expert in the subject matter and in the art of witnessing. He or she most likely knows the subject matter better than counsel and has the experience to hedge the answer and avoid close questioning. The best approach is to elicit the facts you need and not prolong the engagement. Frequently, given the expert's knowledge and the use of rebuttal and surrebuttal testimony to respond to other experts' testimony, parties will decide to waive cross-examination of each other's witnesses by mutual agreement. Subject to the ALJ's approval, testimony will then be submitted by affidavit without having the witness appear.

If the witness does not know the answer to a question, the examiner may respond by asking that the witness accept an answer "subject to check" ("Will you accept subject to check that Typical Utility has \$1,214 invested in poles?"). The attorney likely knows that this is the right answer and is shifting the onus upon the witness to confirm this fact and to inform the parties if it is wrong. There is no obligation on the witness to accept something subject to check, but usually witnesses do so to maintain credibility. Accepting subject to check is a valuable time-saving tool, if used correctly, for easily verifiable facts. Not all ALJ's permit the practice.

Cross-examination is typically limited to topics covered in the testimony and exhibits sponsored by the witness unless there are reasons for departing from this rule. A departure may be justified, for example, if a party is seeking to elicit from the witness information that cannot readily be obtained in any other way, or if the result of limiting the testimony would be that the witness would be recalled later. On-the-record data requests should be avoided in cross-examination. Discovery should be completed before the hearings.

c) Redirect

Following cross-examination, redirect examination by the sponsoring party is permitted but confined to matters brought out on cross. A short, off-the-record conference between counsel and the witness is usually allowed.

d) Recross

The fourth and final step of the appearance is re-cross of the witness by the adverse parties, confined to matters brought out on redirect.

e) Questions by the ALJ

The ALJ may question the witness but normally will wait until all parties have completed their examination of the witness. The ALJ will interrupt when the witness and counsel are at cross purposes when the record may not reflect with clarity what the witness intends to convey or when, for some other reason, assistance is needed to assure orderly development of the subject matter. At the close of cross or redirect, the ALJ may question the witness to clarify any confusing or ambiguous testimony or to develop additional facts in order to develop the record sufficiently.

f) Closing the Presentation

When cross-examination is completed, a witness will be excused (subject to recall at the ALJ's discretion).

14. Rules of Evidence

The traditional common law rules of evidence were developed for formal civil and criminal trials before judge and jury. These are somewhat relaxed in administrative proceeding. Evidence inadmissible by common law standards may be admissible, so long as it is of the kind that usually affects fair-minded people in the conduct of their daily and more important affairs.

On the other hand, while technical rules of evidence are less important in administrative proceedings, sound judgment concerning lack of adequate probative value of the proffered evidence is more important than ever. The ALJ will strike, upon objection or upon the ALJ's own motion, evidence so confusing, misleading, prejudicial, time-wasting, or cumulative that its pernicious influence outweighs its probative value. The ALJ may rule that the authenticity of such documents shall be deemed admitted unless written objections are filed within a specific time.

- a) **Hearsay** - Hearsay, in the law of evidence, is testimony not of what the witness himself saw, heard, or otherwise observed, but of what he heard others tell him or say about the matter. Hearsay may be admitted in an administrative proceeding if it appears reliable and the nature of the information and state of the record make it useful. It usually must be corroborated in some way (confirmed by another source). Uncorroborated hearsay may be admitted and given whatever weight the ALJ finds that it deserves. However, to become a finding of fact, hearsay must be corroborated by evidence in the record.¹⁹³
- b) **Opinion Evidence** - Opinion evidence is the conclusion of a qualified expert based upon a given set of facts or conditions in the record.
- c) **Best Evidence** - Sometimes a copy of a document is offered instead of the original. The accuracy and authenticity of the document will normally be assumed unless questioned.

¹⁹³ *Walker v. Unemployment Compensation Board of Review*, 27 Pa. Commw. 522, 367 A.2d 366 (1976).

15. Oral Argument

Oral argument is an opportunity for each party to voice its position on one or more issues in the case before the ALJ or the Commission in a debate type format. This is not a common practice at the PUC. Rate cases are complex affairs better suited to presentation in writing. Moreover, the timeframes of tariff suspension are tight. However, the ALJ, either on his or her own motion or at the request of a party, may order oral argument on any aspect of the case.¹⁹⁴ The Commission may also agree to hold an oral argument in certain matters when pending before the Commission itself (as opposed to the ALJ).

16. Filing and Service of Briefs

A brief is a writing that intertwines the record facts developed at the hearing with the pertinent law and policy, creating the arguments that form a party's position. These documents are not often "brief", meaning short, but they are much less voluminous than the full record in a rate case. The trick to brief writing is to concisely set out a structured argument that is readable and compelling.

The schedule setup at the prehearing conference generally allows for both main and reply briefs in rate cases, with the parties exchanging them simultaneously.¹⁹⁵ Commission regulations cover the structure and filing of the briefs, which, at the ALJ's discretion, may be required to include proposed findings of fact and conclusions of law.¹⁹⁶ If you are participating in the revenue requirement portion of the case and are offering adjustments, you will be instructed to follow the format of presenting them in a spreadsheet attached to your brief. The ALJ may require the parties to follow a briefing outline that sets forth the order in which the issues are to be presented, e.g., rate base followed by expenses, followed by rate of return, followed by rate structure, etc.

¹⁹⁴ Regs. § 5.532.

¹⁹⁵ Regs. § 5.502(d).

¹⁹⁶ Regs. §§ 5.501 (Content and form of briefs) and 5.502 (Filing and service of briefs).

Typically, the ALJ will officially “close the record” after the hearing is concluded and no further evidence may be adduced absent a formal reopening. The facts argued in brief are strictly limited to those placed on the record and no other.¹⁹⁷ Commission reliance upon facts not of record is grounds for reversal on appeal, so sticking to the record is in your own best interest.

Your brief should contain precise references to the transcript or the testimony/exhibit that you are relying upon, by page and line number, so that the ALJ and other parties can confirm the validity of your citation. For legal citation, the Commission’s regulations require no specific form, but you may wish to follow the traditional formats recommended in *A Uniform System of Citation* (i.e., “The Bluebook”).¹⁹⁸

Do not make the mistake of raising an issue for the first time in your reply brief. This is unfair to the other parties because they do not have an opportunity to respond. The opposition will likely complain loudly, and the ALJ will likely disregard your “new” argument.¹⁹⁹

Finally, persons may participate in briefing without having participated in the hearing or even without party status. *Amicus curiae* (“friend of the court”) briefs are recognized in Commission practice.²⁰⁰ The same rules described above on brief writing apply here.

I. Decision by the ALJ and the Commission

1. Recommended Decision by the Administrative Law Judge

Once the ALJ receives the parties’ briefs and reply briefs (or even before then), he or she then sets about the task of preparing a recommended decision for consideration by the full Commission. In a rate case the ALJ has no authority to “rule” on the case, but rather submits a

¹⁹⁷ There are ways to get additional facts into the record—for example, through official and judicial notice—but prior notice is required. Regs. § 5.408.

¹⁹⁸ <https://www.legalbluebook.com/Public/Introduction.aspx>

¹⁹⁹ Presenting an adjustment for the first time in a main brief may also be problematic. Even if a party believes an adjustment is based upon law or prior precedent, the intent to propose an adjustment should be identified on the record to provide an opportunity to present facts in rebuttal.

²⁰⁰ § 5.501(e) (“A person interested in the issues involved in a Commission proceeding, although not a party, may, without applying for leave to do so, file amicus curiae briefs in regard to those issues. Unless otherwise ordered, amicus curiae briefs shall be filed and served in the manner and number required and within the time allowed by this section, absent good cause.”).

recommended resolution of the issues.²⁰¹ The ALJ will follow case precedent, the rulings of prior Commissions, and applicable court decisions.

The Commission officially requires that a recommended decision in a rate case be submitted by the ALJ two months prior to the end of the suspension period to allow the commissioners adequate time to review the case and prepare for a final order.

2. Exceptions and Reply Exceptions

The ALJ's recommended decision will be served upon you by the Secretary via mail or electronic service. The Secretary's cover letter will provide you with the timing for your next filing—exceptions (generally 20 days from the letter) and reply exceptions (10 days from exceptions), as well as the permitted length.²⁰²

Exceptions are a form of brief containing a concise statement of any disagreement, legal or factual, with the ALJ's decision. Rules regarding exceptions may be found in the Commission's regulations.²⁰³ If you disagree with a settlement that is recommended for approval by the ALJ, you may file exceptions.²⁰⁴

Exceptions are formatted numerically starting with "Exception No. 1", and each exception must "identify the finding of fact or conclusion of law to which exception is taken and cite relevant pages of the decision. Supporting reasons for the exceptions shall follow each specific exception."²⁰⁵ Usually, in a base rate case, each exception follows an issue or rate adjustment that the ALJ accepted or rejected.

If you wish to preserve an issue for Commission decision, it is essential that you take exception. As described in the following section, any issue to which exception is taken will be voted upon by the Commission. If no exception is taken, then the issue will not be voted upon, unless at the independent request of a commissioner.

²⁰¹ Code § 335(a).

²⁰² Commission regulations specify the length as 40 pages (exceptions) and 25 pages (replies), but the parties may agree to, or the Commission may order, a different arrangement. Bottom line: follow the secretarial letter's instructions.

²⁰³ Regs. § 5.533 *et seq.*

²⁰⁴ Regs § 5.537.

²⁰⁵ Regs. § 5.533(b).

Reply exceptions are responses to the exceptions filed by the other parties and labeled as such (e.g., Reply to Typical Utility Exception No. 3). Thus, for example, if the ALJ rules against Typical Utility and in favor of a BI&E wage adjustment, the utility would file the exception and BI&E would reply. As with exceptions, reply exceptions should be concise and to-the-point.

The page limits are tight where there are many unsettled issues, and this forces you to distill your position even more than you did in briefs and replies. Do this by citing to the pages in your brief and reply and by summarizing the arguments you made there. Do not simply “cut and paste.”

3. Commissioner Consideration

The Commission is under no obligation to accept the ALJ’s recommendations. It reviews the case *de novo* (“anew”), meaning that the ALJ decision is advisory only and the Commission takes a fresh look. However, the Commission usually gives much weight to the recommended decision (or should), because the ALJ heard the case firsthand and is more intimately involved with the case than the commissioners ever could become.

The commissioners have access to the transcripts, admitted testimony and exhibits, briefs, reply briefs, recommended decision exceptions, and reply exceptions of the ALJ and parties (i.e., all documents that were admitted on the record). After the recommended decision is submitted and exceptions filed, the Commission’s Office of Special Assistants (OSA) prepares a recommended order or can prepare “polling sheets” for use in Public Meeting. After OSA prepares an Order, the commissioners commence their review of the case, and the Order is approved in Public Meeting. If polling sheets are used, each individual exception is listed on the polling sheet and voted on by the commissioners at a Public Meeting. The commissioners do not simply vote upon the total bottom-line request but poll on every excepted issue. Only after the poll is taken and the majority position decided is the allowed revenue level known. Commissioners will frequently offer motions or statements on single issues, groups of issues, or even the entire case—but, again, each issue is identified and resolved individually on its merits.

The majority position and the rationale for each polling result are then put into the form of an order and entered. Code § 301(d) provides that no order shall be valid unless a “majority of the members of the commission serving in accordance with law” approve it. The third sentence of Code § 1308(d) further provides that the entire request of the utility shall go into effect (subject to later refund with interest) if a final decision is not rendered by the end of the

suspension period. To avoid this outcome—even though a commissioner may disagree with the majority resolution of some of the issues leading to the final order—he or she may vote for that order as a reasonable compromise. Individual commissioners may file a separate concurring and/or dissenting statements.

You will recall that the utility starts the rate case by filing one or more new tariffs listing higher prices for service. The Commission’s final order normally will allow charges that are different from those listed in the utility’s original proposed tariff pages. Thus, the utility must re-file tariffs to comply with the final order. The proposed tariff is withdrawn and a new one submitted. This “compliance” tariff is examined by TUS, and, if in accordance with the Commission’s final order, is approved by secretarial letter.

The date of approval of this compliance filing (or some other date up to the end of the suspension period) then becomes the effective date of the new rates.²⁰⁶ The new rates will apply either to service rendered on and after a certain date, or for bills rendered on and after a certain date.

4. Post-Final Order Procedures

After a final order has been issued by the Commission, there are several courses of action available if you disagree with the outcome.

a) Appeal

The Commission’s decision may be appealed to a court of law for mistakes of fact or law or for lack of substantial evidence. The Commonwealth Court²⁰⁷ is a special appellate body that hears cases originating in administrative agencies and other governmental units, including the PUC. The rules of the court may be found in the Rules of Appellate Procedure (RAP).²⁰⁸ Under the rules an appeal must be taken “within 30 days after the entry of the order” (meaning the final order, not the order approving the compliance filing).²⁰⁹ Filing an appeal does not postpone the

²⁰⁶ If the date of approval of the compliance filing is after the end of the seven-month suspension period, rates will be effective retroactive to the end of the suspension period. *Bell Telephone Company v. Pa. PUC*, 452 A.2d 86 (1982).

²⁰⁷ <http://www.pacourts.us/courts/commonwealth-court/>.

²⁰⁸ Online at: <http://www.pacode.com/secure/data/210/210toc.html>.

²⁰⁹ RAP Rule 1512(A)(1).

effect of the order (i.e., the effectiveness of the new rates) unless specifically stayed by the court or Commission.²¹⁰

Appeals to the Commonwealth Court are of right, meaning the court must hear your case. The next appellate stage is to the Pennsylvania Supreme Court, which has the discretion to either reject or accept the petition for allowance of appeal.

b) At the Commission

You may file several post-final order pleadings asking the Commission to revise its order. Petitions for reconsideration, rehearing, reargument, clarification, or supersedeas are recognized under Commission practice²¹¹ and must be filed within 15 days of order entry.²¹²

Such filings may act to postpone the 30-day appeal filing deadline. When the underlying Commission order is appealed (or is likely to be appealed), however, RAP provides that the Commission must act within the 30-day appeal period or lose its ability to act further in the matter.²¹³ For this reason the Commission gives expedited treatment to all petitions for reconsideration or rehearing filed. Most often the Commission will grant reconsideration “pending review on the merits” to stop the 30-day clock and then address the substance later.

The lesson is obvious: (1) file your petition for rehearing or reconsideration as soon as possible after entry of the Commission’s order; and (2), to protect your right to appellate review, also file an appeal to the Commonwealth Court within 30 days after entry of the Commission’s order if the Commission has not acted. If a petition for reconsideration or rehearing is filed more than 30 days after the entry of the order, then expedited treatment by the Commission is unnecessary.²¹⁴

²¹⁰ RAP Rule 1701. Changing the order is prohibited, but enforcement is permitted.

²¹¹ Code §§ 703(f) (rehearing) and (g) (rescission and amendment of orders); Regs. § 5.572.

²¹² Regs. § 5.572(c).

²¹³ RAP Rule 1701(b).

²¹⁴ Despite the provisions of RAP Rule 1701(b), the Commission has successfully granted reconsideration in appealed cases over 30 days after the original order was entered by making the grant of reconsideration contingent upon the withdrawal of the appeal. This procedure was affirmed by the Commonwealth Court in *Tripps Park Civic Association v. Pennsylvania Public Utility Commission*, 52 Pa. Cmwth. 317, 415 A.2d 967 (1980).

Supersedeas is a request to the Commission that it stay (postpone) enforcement or implementation of its decision, usually pending the outcome of an appeal. To determine if supersedeas is warranted, the Commission applies the following criteria:²¹⁵

1. The Petitioner is likely to succeed on the merits.
2. Without the requested relief, the petitioner will suffer irreparable injury.
3. The issuance of a stay will not substantially harm other interested parties.
4. The issuance of a stay will not adversely affect the public interest.

A petition for rehearing seeks an opportunity to further develop an evidentiary record, which could change the Commission's decision. To do so, you must allege the possession of after-discovered evidence that was not in existence or discoverable through the exercise of due diligence at the time of hearing.

A petition for reconsideration requests the Commission to reevaluate and change a prior decision without alleging the need to further develop the record.²¹⁶ The standard applied by the Commission requires the petitioner to raise "new and novel arguments, not previously heard, or considerations which appear to have been overlooked or not addressed by the Commission."²¹⁷

²¹⁵ In *Pennsylvania Public Utility Commission v. Process Gas Consumers Group*, 502 Pa. 545, 467 A.2d 805 (1983) our Supreme Court adopted the standards established by *Virginia Petroleum Jobbers Association v. Federal Power Commission*, 259 F.2d 921 (D.C. Cir. 1958). The Commission places the greatest weight on the final 3 criteria, since the Commission has already ruled against the Petitioner on the merits and is unlikely to decide, in a supersedeas petition, that its prior decision was wrong. *Pa. PUC v. UGI Corp.*, 57 Pa. PUC 83 (1983).

²¹⁶ See *Abramson v. Pennsylvania Public Utility Commission*, 489 Pa. 267, 414 A.2d 60 (1980); *Brinks v. Pennsylvania Public Utility Commission*, 16 Pa. Cmwlth. 300, 328 A.2d 582 (1974).

²¹⁷ *Duick v. Pa. Gas & Water Co.*, 56 Pa. P.U.C. 553 (1982).

III. Rate Cases/Substance

A. Why a Utility Files

A utility proposes to increase rates because of what it considers an inadequate profit (return on investment) from its operations. All utility operations have a cost impact on the income statement. Costs are deducted from revenues, and the net result flows down to the “bottom line”, which is negative, positive, or not positive enough.

In the period following a rate case during which the new rates are in effect—when costs or usage change, contrary to the best assumptions used in setting the rates for that period—the utility’s financial bottom line is affected. Sometimes changes are offsetting, and the rate of return will remain adequate. At other times operating costs will increase without an adequately counterweighing increase in revenues. Or, revenues may decrease with no countervailing expense decrease. Significant events, such as placing new facilities in operation or a substantial drop in customer usage, will almost certainly cause a shortfall in net operating income, which deteriorates shareholder earnings.

The utility’s decision to apply for higher rates is typically made for several basic reasons:

- New facilities have been placed in service and need to be incorporated into the company’s rates.
- Expenses have increased (e.g., increased labor costs, supplies, taxes).
- Sales (revenues) have diminished.
- The cost of attracting needed capital has increased.

B. Utility Capitalization

Investors purchase two basic types of financial instruments: bonds (debt) and common stock (equity).²¹⁸

The shareholders of a utility are those persons, companies, or other institutions that own common stock (equity) in the corporation. Shareholders are the owners of the company and stand at the end of the payment line. Only after all expenses are paid do the company’s owners earn a profit and receive a return on investment. If no money is left over, shareholders receive nothing.

²¹⁸ There is a third type of security, preferred stock, which is a hybrid of debt and equity.

Therefore, the failure to earn a reasonable return is the reason most often cited by the utility for its decision to seek a rate increase.

Equity shareholders are not guaranteed a profit by regulators—a common misunderstanding. Owners are given an opportunity, under prudent and reasonable management, to earn the return allowed by the Commission based upon the expense/investment/usage mix determined in the rate case.

A bond investor is not an owner, but rather holds a contract to be paid interest and, eventually, a return of the principal. Interest payments are an expense to the company and paid before the shareholders receive anything. A good analogy is the bank that finances your family automobile. Unless you can compensate the bank for the use of its money and the risk you represent—and the risk must be a reasonable one—you will receive no loan. A finance company might provide the capital, if your credit rating is low, but at a much higher rate of interest. If your income is too low to cover the payments, you might not find an institution willing to undertake the risk. The same is true in the world of corporate finance.

These investments by third party equity and bond investors provide the capital necessary to build new infrastructure to deliver services. The source of capital to construct utility plant, for the most part, is not ratepayer revenue. Outside capital is needed. Without investors' money, expansion, or even improvement, of existing facilities would not be possible.

In the international marketplace of investment capital, there is an endless choice of investment opportunities. Utilities shop for capital in this competitive environment. No one can be forced to buy utility stocks and bonds. Investors will not invest unless compensated for the use of their money and the risk they assume. This is an irony of ratemaking—monopolists in a competitive market.

Investors must be induced to invest by financial results and actual performance. If expenses consume all revenues because of insufficient rates and/or inefficient management practices, and no money is available to cover interest and pay dividends, investors will look elsewhere. New or replacement facilities, although needed, will not be built on reasonable terms. If rates are set too low, the cost to attract necessary capital will be greater, and, ultimately, ratepayers will be required to pay higher charges than if rates had been adequate. The old, unreliable, more costly-to-operate plant will remain in operation. The quality of service may deteriorate consequently.

On the other hand, ratepayers have an interest in the lowest rates consistent with reliable service.

C. Just and Reasonable Rates

Pennsylvania statutory law provides that any rates charged by a utility must be just and reasonable.²¹⁹ Exactly how to define this nebulous term, no one can say definitively. The problem is analogous to U.S. Supreme Court Justice Stewart’s remark regarding pornography, “I cannot tell you what it is, but I know it when I see it.” Beyond an overly-broad judgment that \$1.00/kWh electricity is extortion and 1¢/kWh is larceny, the costs and claims underlying proposed rates are carefully reviewed, taking little else for granted.

Rate regulation attempts to accomplish several, often conflicting, objectives:

- Resist the monopoly temptation to:
 - Reduce output (Code § 1501);
 - Maximize rates (Code § 1301); and
 - Engage in price discrimination (Code §§ 1303 and 1304).
- Replicate the results of effective competition.
- Promote efficiency and conservation.
- Ensure adequate supply of service.
- Demand control or consumer rationing.
- Promote financially stable utilities by giving them a reasonable opportunity to earn a fair rate of return.

Utility management makes many daily decisions regarding operations, all of which have a cost impact. On the one hand, the decisions of the utility managers chosen by the shareholder/owners of the corporation—while subject to review—are entitled to weight. The PUC does not and should not act as a super board of directors and second guess utility

²¹⁹ Code § 1308.

management in the manner of a Monday morning quarterback.²²⁰ On the other hand, ratepayers cannot be expected to bear costs that are imprudently or unreasonably incurred.

Thus, utilities are held to the standard of a familiar legal fiction: “the reasonably prudent man.” The question to be answered is whether a reasonable person would have made the same decision under similar circumstances. The reasonably prudent person is neither a brilliant man nor a soothsayer. The standard contemplates a person of normal intelligence, foresight, and judgment.

There are constitutional issues involved in regulation. The two most important to utility regulation are the 5th Amendment’s prohibition against confiscation (no taking of private property for public use without just compensation) and the 14th Amendment’s guarantee of due process (no person shall be deprived of property, without due process of law).

A very considerable body of case law has been developed over the years that interprets these provisions. The concept of a reasonable return on used and useful property was identified early on in the development of price regulation theory. In 1898, the U.S. Supreme Court held that “the basis of all calculations as to the reasonableness of rates to be charged...must be the fair value of the property used by it for the convenience of the public.”²²¹

By 1923, the court felt the matter to be well settled:

Rates which are not sufficient to yield a reasonable return on the value of property used, at the time it is being used to render the service, are unjust, unreasonable and confiscatory. What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.²²²

Utility expenses that are not reasonably and prudently incurred or that are unnecessary to the rendition of utility service may be removed from the cost of service without violating the taking

²²⁰ *Bell Telephone Co. of Pa. v. Driscoll*, 343 Pa. 109, 21 A.2d 912 (1941). But see *Philadelphia Electric Co. v. Pa. P.U.C.*, Pa. Cmwlth. 455 A.2d 1244 (1983), reversed 460 A.2d 734 (1983) (where the Pennsylvania Supreme Court reversed the Commonwealth Court, holding that “...the legislature intended, through [Code §1903 relating to registration or rejection of securities certificates], to enable the PUC to intercede with respect to management’s capital spending programs when these are of such great size as to require special securities financing. These programs, having extraordinary potential for determining the course of rates and service, are not mere daily management matters reserved for corporate autonomy.”).

²²¹ *Smyth v. Ames*, 169 U.S. 466 (1898).

²²² *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 690 (1923).

clause. The *Hope*²²³ test requires courts to examine the balance struck by the ratemaking authority between the competing interests of utility investors and consumers.²²⁴

D. Accounting and Public Utilities

1. Business Accounting

Accounting is a system of compiling data on business operations in a usable and reliable format. Accounting results are used by company officers to determine the cost of production, control costs, and make other important management decisions. Potential investors and financial analysts scrutinize accounting reports to determine whether the company is a good investment. The PUC prescribes a utility's chart of accounts and uses the resulting data to establish the proper price that may be charged for utility service. The books of accounts of a utility are a basic part of, and an essential starting point for, many issues in a rate case.

Accounting reports the historical operating results of the company ("per books"). Ratemaking, however, is concerned with the cost of providing service in the future period during which the newly-established rates will be in effect. Therefore, historical accounting data is annualized and normalized in a rate case to more accurately forecast the future. Further, regulators are concerned with the reasonableness and prudence of expenses and the protection of ratepayers from a monopolistic market structure. Consumers should not be required to subsidize inappropriate activities, inefficiency, or non-related enterprises, although the unadjusted accounting results may reflect them. Therefore, per books accounting results are adjusted in many ways and for a variety of purposes in a rate case.

It is essential to have some basic understanding of accounting before attempting to master the intricacies of a rate case. A discussion of basic accounting principles is contained in Appendix A. It is highly recommended that you read this before proceeding further.

2. Uniform System of Accounts

A uniform chart of accounts provides comprehensive data using an agreed-upon system of defined account descriptions that does not change from company to company. Accounts are

²²³ *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

²²⁴ *Takings Clause Analysis of Utility Ratemaking Decisions: Measuring Hope's Investor Interest Factor*, Sean P. Madden, *Fordham Law Review*, Vol. 58, Issue 3 (1989); <http://ir.lawnet.fordham.edu/cgi/viewcontent.cgi?article=2862&context=flr>.

typically defined by an account number and a caption or header. These are then organized and coded by account type (assets, liabilities, equity, revenue, expenses, and contra-accounts are the basic categories). This mutual understanding of the contents of any particular account aids the exercise of investigating, analyzing, and interpreting the data of public utility companies to inform regulators and the public, including the investment community, of the actual results of utility operations.

Most state public utility commissions, including Pennsylvania, require that utilities maintain their books in conformity with a prescribed Uniform System of Accounts (USOA),²²⁵ as developed by several authorities: the FERC (for gas²²⁶ and electric²²⁷), the FCC (for telephone²²⁸), and the National Association of Regulatory Utility Commissioners (for water and wastewater²²⁹). The PUC has authority over the utilities' books of account and, from time to time, may authorize changes.²³⁰

The USOA prescribes what items of income and expense and what assets, liabilities, and capital should be included under any particular account heading and where that account should appear on the balance sheet or income statement. Thus, for example, when attempting to record an invoice for electric pole cross arms that have been installed, the electric utility accountant knows that the USOA defines the proper classification as FERC Plant in Service "Account 364" entitled "Poles, towers and fixtures" the description of which is "the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires." As importantly, a third person reviewing the company's books understands that Account 364 represents installed, overhead support facilities and is used and useful property as a part of the company's distribution plant.

²²⁵ See Regs. 52 § 57.42 (Electric); Regs. 52 § 59.42 (Gas); Regs. 52 § 63.32 (Telephone); and Regs. 52 §65.16 (Water).

²²⁶ 18 CFR, Part 201; <https://www.gpo.gov/fdsys/pkg/CFR-2012-title18-vol1/pdf/CFR-2012-title18-vol1-part201.pdf>.

²²⁷ 18 CFR, Part 101; <https://www.gpo.gov/fdsys/pkg/CFR-2011-title18-vol1/pdf/CFR-2011-title18-vol1-part101.pdf>.

²²⁸ 47 CFR § 32.1 *et seq.*; <https://www.gpo.gov/fdsys/pkg/CFR-2009-title47-vol2/pdf/CFR-2009-title47-vol2-part32.pdf>.

²²⁹ Available for purchase by contacting NARUC. <https://www.naruc.org/>.

²³⁰ Code § 1704.

E. Concept of the Test Year

The calculation of rates is founded in the construct of a test year, a twelve-month period, typically ending December 31, during which the historic balance of assets, expenses, and revenues can be reviewed. If calculated accurately, the use of a test year allows the prudently-managed utility to recover all expenses and a reasonable return—no more and no less. In a very simple sense, establishing utility rates sets a ratio between the utility’s costs and customer usage.

The ultimate purpose is to predict the operating results of the utility during the period for which the rates being set will function (i.e., “the rating period”) by matching the revenues (sales) of the utility with the expenses and investment that will be incurred during that period. Therefore, the historic results are employed to predict the results likely to occur during the rating period. Test year controversies usually are disputes about the point(s) in time at which revenues or expenses should be measured or collected.

Conversion of the historic, “per books” results to a valid test year, rate-setting basis entails two basic steps: in-period and out-of-period adjustments. These are generically and rather loosely referred to as “pro-forma” adjustments. That is, to ensure that the financial data used to calculate the revenue requirement matches the period when rates will be in effect, pro-forma adjustments are made to revenues, expenses, and rate base. These adjustments change test year data to reflect the full-year effect of major known and measurable changes in revenue, expense, and investment levels, which will occur during or at the end of the test year.

First, abnormal, non-annual events that have occurred during the twelve-month test period must be identified and removed. If this exorcism were not performed, an item of expense (or revenue) that occurs only once every 50 years, but which happened to occur in the test year, would be included as an annual event in rates and unfairly recovered every year. This is the process of amortization and normalization. For our purposes, expenses can be categorized into three types: (1) non-recurring; (2) infrequently recurring; and (3) regularly recurring.

Non-recurring expenses should be either excluded from rates altogether, because future ratepayers should not be required to pay for that which will never occur again, or, in the other

view, amortized (recovered over a reasonable period of years), because this is a reasonable item of expense that the company should recover (just not all at once).²³¹

Expenses that will probably occur again, albeit irregularly and infrequently, should be “amortized”. An example would be damages caused by a hurricane. In the past, the Pennsylvania PUC has stated that:

Expenses that occur irregularly during an extended period of years, but are certain of eventual recurrence, are a legitimate charge to ratepayers. Therefore, spreading of this expense over years of recurrence is logical.²³²

Thus, if a hurricane were forecast to recur every 20 years, the associated expense would be amortized over that same period (i.e., one-twentieth per year).

On the other hand, expenses that: are regularly recurring should be “normalized.” Normalization simply means that a normal, annual amount of expense is determined and included in rates. For example, assume that during the test year Typical Utility employed 15 workers, but that in the 5 years before only 10 persons worked for the company and, further, that the company recently (post-test year) laid off the 5 new workers. Thus, the normalized number of employees is 10. If rates were set based on 15 employees, Typical Utility’s rates would be excessive to ratepayers.

There are three types of test years used in Pennsylvania:

- Historic Test Year (HTY). Accounting results are for a period that is past at the time of rate case filing.
- Future Test Year (FTY). Results are projected when filed, but historic by the time rates become effective.
- Fully Projected Future Test Year (FPFTY). Projected financial results are used for a period that begins at the same time as rates become effective.

In some states, regulators exclusively employ a historical test year (i.e., an experienced twelve-month period²³³) for the prospective rate-setting process, believing that adjusted historical results are an effective basis upon which to make future projections. However, this is not

²³¹ Where an expense is amortized, the unamortized (uncollected, outstanding) balance is rolled over in the next rate case. For example, suppose \$100 of expense is amortized over 10 years. For 10 years, each ensuing rate case should recognize \$10 per year of amortized expense. At the end of 10 years the expense would be considered recovered, and no further amortization of that expense allowed.

²³² *Pa. P.U.C. v. York Water Co.*, 78 PUR 3d.113, 132 (1968).

²³³ For example, using the adjusted results for calendar year 2016 for a rate filing in 2017.

necessarily a valid assumption, and, in periods of high inflation, elevated cost of money, dwindling and even negative growth in demand for service, the unadjusted historical experience of the company is not a valid future indicator.

The forward-looking test years, both the FTY and the FPFTY, are somewhat different animals. The need for normalization and amortization adjustments with respect to the historic test year is obviated for larger gas and electric utility companies that base filings on budget information. The budget process itself generally assumes normal, unextraordinary operations, and, if the future test period coincides with the rating period, no adjustments need be made. The focus is not that different from an HTY. It merely shifts from the accuracy of the historic test year to predict future results to the accuracy of the budget process.

Among the advantages cited on behalf of the future test year, three stand out as the most important. First, this methodology allows rates to more closely reflect utility operating factors and general economic conditions during the rating period. Second, the enhanced ability of utility management to more fully and expeditiously recover current costs will result in lower rates for consumers. Third, current cost recovery via projected data should reduce rate case filings and thereby mitigate the administrative burdens on regulatory agencies and reduce rate case expense.

Pennsylvania rate case filings were originally based exclusively on a historic test year. Starting in approximately 1989, the Commission began using a modified future test year approach under which utilities are given the option of either employing a single historic test year or a historic test year and a future test year together.²³⁴ To avoid “stale” test years, the end of a historic test year is required to occur no later than 120 days from the date of filing the case, and a future test year is required to begin the day after the historic test year has ended.²³⁵ Thus the future test year is a historic one by the time that rates go into effect (assuming the full suspension

²³⁴ For example, using the adjusted results for calendar year 2016 and a forecast of 2017 for a rate case filed in 2017.

²³⁵ Regs. § 53.52(b)(2) (Companies must file an “operating income statement of the utility for a twelve-month period, the end of which may not be more than 120 days prior to the filing. Water and wastewater utilities with annual revenues under \$100,000 and municipal corporations subject to Commission jurisdiction may provide operating income statements for a twelve-month period, the end of which may not be more than 180 days prior to the filing.).

period was consumed), but is still more contemporaneous than a strictly historic test year, which is 1 year old by that time.²³⁶

The use of a fully projected future test year (“the twelve month period beginning with the first month that the new rates will be placed in effect after application of the full suspension period”) was recognized by the General Assembly under Act 11 of 2012.²³⁷ Historic data is still required to be submitted to validate the fully projected future test year.²³⁸ The Commission has also expressed interest in back testing prior projections: “Moreover, although there is no reconciliation of revenues and expenses between base rate cases, we expect that in subsequent base rate cases, the utility will be prepared to address the accuracy of the fully projected test year projections made in its prior base rate case.”²³⁹ Regulations addressing the filing requirements for the fully projected future test year have not yet been issued, but, generally, companies now file 3 years of accounting data.²⁴⁰

The legislation acknowledges that certain historic test year precepts must be modified. So, for example, the prior requirement that plant be “used and useful” (i.e., operating at the time it is put into rates) prior to recognition in rates is changed, and the “commission may permit facilities which are projected to be in service during the fully projected future test year to be included in the rate base.”²⁴¹

F. Surcharges and Riders

Before delving more deeply into the mechanisms of a traditional rate case, now might be a good opportunity to discuss what the rate case is not. A rate case establishes base rates²⁴² using the test year, fully balancing all aspects to the utility’s income statement and balance sheet and

²³⁶ This is the arrangement set forth in the Commission’s regulations at § 53.56.

²³⁷ Code § 315(e). For example, using a forecast of 2018 results for a rate filing made in 2017.

²³⁸ Code § 315(e).

²³⁹ *Implementation of Act 11 of 2012*, Docket No. M-2012-2293611, Tentative Implementation Order (May 11, 2012) and Final Implementation Order (August 2, 2012).

²⁴⁰ For a filing made in March of 2017, calendar 2016 (HTY - actual per books adjusted), 2017 (FTY - adjusted) and 2018 (FPFTY - forecast) operating results are all submitted.

²⁴¹ Code

²⁴² Do not confuse the term “base rate”, which is the basic, tariffed charge, not including surcharges, for service rendered, with “rate base”, which is the sum of all utility property used and useful in the public service.

establishing a fair rate of return. Some costs (and investments), however, are recovered outside the base rate case by means of a separately-administered surcharge or rider.

Both the historic and future test year approaches assume that the near-term future can be predicted with reasonable accuracy. However, when a utility's operating costs fluctuate unpredictably, or public policy supports more prompt rate recovery to encourage some desired behavior, a surcharge is established to more rapidly recoup those expenses.

The main purpose of automatic adjustment clauses and surcharges is to reduce “regulatory lag”—the time between the incurrence of an expense or investment and the time it appears in rates. Regulatory lag under an automatic adjustment clause is six months or less, compared to a lag of nine months for a general rate proceeding from when a company submits a letter of intent to file a rate case, when the case is suspended for review and fully litigated, to when new rates go into effect. This nine-month lag (for base rate cases) doesn't even consider the possibility that plant could have been used and useful long before the base rate case was filed. Base rate proceedings are lengthy, since they involve extensive filing requirements, written testimony of utility witnesses, discovery, countervailing testimony of the statutory advocates, and other interested parties' formal evidentiary hearings, and regulatory review of every request for additional revenues.

Various forms of automatic adjustment clauses have been included in fixed utility tariffs in Pennsylvania for over 50 years. These tariff provisions are undertaken under the general rubric of the “sliding scale of rates” authorized under Code § 1307 or pursuant to specific statutory authorization.²⁴³

Primary examples of Code § 1307 sliding scale trackers currently in use are:

- Fuel cost adjustment (timely fuel recovery)
- State tax adjustment surcharge (separate billing of state tax changes)
- Expense trackers (various reasons)

²⁴³ “Any public utility [with certain exceptions] may establish a sliding scale of rates or such other method for the automatic adjustment of the rates of the public utility as shall provide a just and reasonable return on the rate base of such public utility, to be determined upon such equitable or reasonable basis as shall provide such fair return.”

Several examples of specific automatic adjustment mechanisms authorized by separate statute include:

- Distribution System Improvement Charge (Code §1353)
- Electric default service costs (Code §2807(e)(3.9))
- Smart meter technology (Code §2807(f)(7))

The widespread use of trackers and surcharges has reduced regulatory reliance on full-blown rate cases for cost recovery and provided a valuable financial management tool. Base rate cases and the review of earnings are not abandoned. Most of these mechanisms require that the cost be “trued up” in a test year rate case at some point, because the base rate case remains the tried-and-true arbiter of the balance between revenues, expenses, and investment in setting a proper earnings level.

1. Fuel Clauses

The cost of oil, natural gas, and other fuels can be highly volatile and impossible to accurately project. Separate clauses for the recovery of fuel costs were initiated during the 1970s, when the Organization of Petroleum Exporting Countries (OPEC)²⁴⁴ cartel established reduced production limits for its member countries, creating an oil pricing shock and making it extremely difficult for electric utilities to forecast their oil bills or for gas distribution companies to project the cost of their natural gas portfolios. Under the regulatory lag of base rate recovery, utility prices could not keep up with energy price fluctuations.

Fuel cost recovery therefore was designed to occur separately under a fuel adjustment clause. The clause flows through only changes in the price paid for fuel and includes no profit or other cost recovery to the utility. It is “dollar for dollar.”²⁴⁵

Consistent use of fuel clauses in Pennsylvania began in 1969 for natural gas utilities and 1972 for electric utilities. After the OPEC oil embargo in 1973, fuel costs across the country increased by 80 percent on average. Higher fuel costs were also caused by Congress’ passage of the deregulatory Natural Gas Policy Act of 1978 (NGPA) with the intended consequence of generating greater domestic supply at a time of shortage by removing price controls.

²⁴⁴ http://www.opec.org/opec_web/en/.

²⁴⁵ Steam companies also use a fuel clause. Water companies with large pumping expenses may also have a similar tariff mechanism.

Pennsylvania experimented with several types of natural gas utility fuel clauses between 1969 and 1984, as detailed in the original Handbook. Following this period of trial and error, the General Assembly added Section 1307(f) to the Code in 1984 for gas distribution companies with gross intrastate revenues exceeding \$40 million.²⁴⁶ This provision is currently effective, under which the larger gas company annually files a proposed tariff (with a prospective six-month effective date) “reflecting actual and projected increases or decreases in their natural gas costs...” True-ups of projected estimates to actual experience are then made annually through the “E factor.”²⁴⁷

In its § 1307(f) filing, the gas distribution company must demonstrate that the proposed rates are “just and reasonable” pursuant to “a least cost fuel procurement policy, consistent with the utility’s obligation to provide safe, adequate and reliable service...”²⁴⁸ In making this demonstration the utility must show that, among other things, it has “fully and vigorously represented the interests of its ratepayers” in proceedings before the [FERC]; taken all prudent steps necessary to negotiate favorable gas supply contracts and to relieve the utility from the adverse terms of existing contracts; taken all prudent steps necessary to obtain lower cost short- and long-term gas supplies; and has not withheld from the market or caused to be withheld from the market any cheaper gas supplies.

A § 1307(f) case is a fully litigated affair (but usually settled), with the requirement of public input hearings where there is an indication of public interest. After the end of the twelve-month period covered by the fuel recovery rates, the utility then files a full reconciliation statement comparing the actual expenses with that forecasted, and the difference is refunded to/recouped from the customers via the E factor adjustment in the ensuing purchased gas cost (PGC) year. Annual audits are conducted to verify that natural gas utility customers have been billed in accordance with approved tariffs, that reported gas and energy costs have been incurred, and that the utility is striving to obtain the most reliable sources of energy at the lowest possible cost.

²⁴⁶ See *National Fuel Gas Distribution Corp. v. Pa. Public Utility Commission*, 473 A.2d 1109, 1117-1119 (Pa. Cmwlth. 1984) (describing the legislative intent behind Code § 1307).

²⁴⁷ Code §1307(f)(3).

²⁴⁸ Code § 1318.

The electric industry fuel clause followed a similar history. The Commission adopted the Energy Cost Rate (ECR) methodology for jurisdictional electric companies in 1979, which incorporated the major provisions of the gas distribution companies' fuel mechanism. The ECR was a levelized rate that applied for a specified twelve-month period. Other similarities to the gas clauses included the need for Commission preapproval, the use of projected costs as a basis for calculating the ECR, the required filing of quarterly reports reflecting ECR costs and revenues, and the use of an over/under reconciliation formula in the equation (i.e., an E factor). There was no legislation prescribing the operation of a fuel clause.

Electric utilities now operate under the 1996 Choice Act, where the supply of electricity may be purchased, at the customer's option, in a competitive market. The EDCs, however, still must supply those customers who make no choice and hence "choose" to remain with the distribution utility.²⁴⁹ In such circumstances, the EDC is the default service provider (DSP) offering an unbundled energy supply rate in addition to the separately-stated distribution and transmission charges. This DSP price is referred to as the "Price to Compare" (PTC) on the PUC's shopping website.²⁵⁰

The Commission's original default service regulations became effective on Sept. 15, 2007²⁵¹ and contained guidelines for DSPs in the areas of procurement, rate design, and cost-recovery. The regulations required that DSP default supply prices be set at "prevailing market" and that electric supply be acquired by competitive bid solicitation, spot market purchase, or a combination of both as required under the 1996 Choice Act.²⁵²

Act 129 of 2008²⁵³ explicitly rescinded this prevailing market price standard and declared instead that the utilities' generation purchases must be designed to ensure adequate and reliable

²⁴⁹ Even though the retail provision of electric generation service has been subject to competition for nearly two decades, most residential customers continue to obtain their generation supplies from their "default" supplier, that is, their regulated electric distribution utility.

²⁵⁰ <http://www.papowerswitch.com/shop-for-electricity>.

²⁵¹ *Rulemaking Re Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant To 66 Pa.C.S. § 2807(e)(2)*, Docket No. L-00040169, Advance Notice of Final Rulemaking Order (Feb. 9, 2007) and Final Rulemaking Order (May 10, 2007).

²⁵² Regs. § 54.186(b)(4).

²⁵³ Governor Edward Rendell signed House Bill 2200, Act 129, into law, effective on Nov. 14, 2008. Act 129 has several goals, including reducing energy consumption and demand. Act 129 also revises the default service requirements contained in Chapter 28 of the Public Utility Code.

service “at the least cost to customers.”²⁵⁴ This is frequently referred to as the “prudent mix” standard. The legislation also prescribed residential rate design that minimally requires a single rate that does not decline with usage (this is the published PTC) and that rates not change more frequently than quarterly.

The Commission’s regulations allow DSPs to use sliding scale rates for recovery of default service costs.²⁵⁵ The default service Policy Statement provides additional guidance to EDCs regarding energy procurement, bid solicitation processes, default service cost elements, rate design, rate change mitigation, rate and bill ready billing, purchase of receivables programs, customer referral programs and supplier tariff uniformity.²⁵⁶

DSP plans cover a multi-year period (2-4 years) and may involve hearings. The plans describe the electric generation supply acquisition strategy for the period of service, the means of satisfying the minimum portfolio requirements, an implementation plan identifying the schedules and technical requirements of competitive bid solicitations and spot market energy purchases, and a rate design plan. Because of the presence of competition, the process is intentionally less rigorous than the gas companies’ 1307(f) filings. The Commission, however, has provided for an “E factor” reconciliation mechanism.

Overall, the Commission’s approach to default service has been to encourage competition. The Act 129 mandates have been criticized as unduly restricting the industry’s transformation to a fully competitive market by the unintended effect of creating a highly-regulated default service product that bears little or no resemblance to market conditions.

[T]he Commission’s main goal in developing a revised default service product is to create a more market-based PTC. This type of product will mitigate the potential for ‘boom [DSP rate too high]/bust [DSP rate too low]’ scenarios to occur...the elimination of potential ‘boom/bust’ cycles will create a more sustainable retail market, which, in turn, should lead to enhanced product offerings to consumers and long-term EGS investments within Pennsylvania.²⁵⁷

²⁵⁴ Code § 2807(e)(3.4). Defined as “The prudent mix of contracts entered into pursuant to paragraphs (3.2) and (3.3) shall be designed to ensure: (i) Adequate and reliable service. (ii) The least cost to customers over time. (iii) Compliance with the requirements of paragraph 3.1 [which requires “a prudent mix of” spot, short-term and long-term purchase contracts].”

²⁵⁵ Regs. § 54.187(f).

²⁵⁶ Regs. § 69.1801 *et seq.*

²⁵⁷ *Investigation of Pennsylvania’s Retail Electricity Market End State of Default Service*, Docket No. I-2011-2237952, Tentative Order (Nov. 8, 2012) and Final Order (Feb. 15, 2013) (“*End State Orders*”).

The proposal chosen for residential customers in the *End State Orders* is to rely on auctions of full requirements, load-following contracts for a mix of terms ranging from a quarter to several years. Review and refinement is ongoing by the Commission and its Office of Competitive Market Oversight as of this writing.

2. State Tax Adjustment Surcharge (STAS)

The State Tax Adjustment Surcharge (STAS) was implemented under the State Tax Procedure Order of the Commission released on March 10, 1970 in response to increases in several state taxes imposed upon public utilities. The changes were dramatic (and they were also retroactive), and utility returns were destabilized. Rather than “bury” the taxes in base rates, thus appearing to be an approved utility rate increase, the Commission required the tax changes to appear as a separate line item on the bill. The STAS permits jurisdictional utilities to recover increases (and refund decreases) in the following tax rates each year: Corporate Net Income Tax; Gross Receipts Tax; and Public Utility Realty Tax. Filings are due March 31 of each year or within ten (10) days after an event requiring recomputation. The surcharge is “rolled into” base rates (i.e., “zeroed out”) according to either the “rate case” or “non-rate case” method.²⁵⁸

3. Distribution System Improvement Charge (DSIC)

The deterioration of our country’s infrastructure, including distribution utility facilities’ state of repair and upgrade, has been of universal concern.²⁵⁹ Rather than follow the standard base rate case model of “build it then face regulatory delay”, regulators and legislators have sought ways to systematically identify the need for replacement and reduce regulatory lag in recovering the investment.

The water industry was the initial focus. In 1996, the Pennsylvania General Assembly enacted § 1307(g) of the Code, which allowed water companies to request approval of a surcharge to recover certain capital improvements. The purpose of the Distribution System Improvement Charge (DSIC), among other objectives, is to provide water utilities with the financial resources needed to accelerate the replacement rate of aging water distribution system infrastructure; recover the depreciation and pre-tax return of non-revenue producing, non-

²⁵⁸ Regs. § 69.55.

²⁵⁹ *American Society of Civil Engineers Report Card for Pennsylvania’s Infrastructure* (2014), https://www.infrastructurereportcard.org/wp-content/uploads/2016/10/ASCE_2014_Report_Card_for_PA_Infrastructure.pdf.

expense reducing projects completed and placed in service between base rate cases; and reduce the potential need for more frequent base rate proceedings, with the attendant increased rate case expense. Such non-revenue producing, non-expense reducing investment includes main and valve replacement, main cleaning and relining, fire hydrant replacement, main extensions to eliminate dead ends, solutions to regionalization projects, and meter change outs. Ratepayers benefit from the DSIC through infrastructure remediation and improved service quality and reliability.

In February 2012, § 1307(g) was repealed under Act 11 in favor of a more comprehensive mechanism that was extended to gas, electric, wastewater, and city natural gas operations, not just water entities.²⁶⁰ Act 11 states that, as a precondition to the implementation of a DSIC, the utility must first file a long-term infrastructure improvement plan (LTIP) for approval by the Commission that is consistent with 66 Pa. C.S. § 1352(a).²⁶¹

The LTIP is a comprehensive review of “eligible property”²⁶² and filed “at least” once every 5 years. Changes can be made periodically as needed. The essence is the requirement that the long-term plan demonstrate the “manner in which replacement of aging infrastructure will be accelerated *and* how repair improvement or replacement will maintain safe and reliable service.”²⁶³ Once the LTIP is approved, the utility may implement a DSIC.

Section 1355 provides that, after notice and opportunity to be heard, the Commission shall approve, modify, or reject the utility’s proposed DSIC tariff.²⁶⁴ DSIC filings are subject to answers and/or complaints consistent with the procedural rules of practice and procedure in Chapters 1, 3, and 5 of the Commission’s regulations.

²⁶⁰ Adding Code §§ 1350-1360. On May 10, 2012, the Commission issued a Tentative Implementation Order and on August 2, 2012, issued the Final Implementation Order. *Implementation of Act 11 of 2012*, Docket No. M-2012-2293611, Tentative Implementation Order (May 11, 2012), Final Implementation Order (Aug. 2, 2012) and Supplemental Implementation Order (Sept. 21, 2016).

²⁶¹ The Commission’s LTIP regulations are at Regs § 121.1.

²⁶² Eligible property is that “part of a distribution system and eligible for repair, improvement and replacement of infrastructure under this subchapter.” Code § 1351. The categories of plant that may be included is listed for each utility industry at this same Code section and is focused on distribution assets.

²⁶³ Code § 1352(a)(6). Capital investments associated with customer expansion projects are not DSIC eligible.

²⁶⁴ Code § 1355.

The formula for calculation of the DSIC, which results in a percentage add-on to the bill, is as follows:

$$\text{DSIC} = \frac{(\text{DSI} * \text{PTRR}) + \text{Dep} + \text{E}}{\text{PQR}}$$

Where:

- DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation.
- PTRR = Pre-tax return rate applicable to DSIC-eligible property.
- Dep = Depreciation expense related to DSIC-eligible property.
- E = Amount calculated under the annual reconciliation feature or Commission audit, as described below.
- PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from existing customers plus netted revenue from any customers that will be gained or lost by the beginning of the applicable service period.²⁶⁵

DSIC allowable costs are depreciation of and pretax return on the eligible assets placed into service during the prior three-month period.²⁶⁶ The depreciation rates are those used in the utility's most recent base rate case. The pre-tax return is calculated using federal and state income tax rates, the utility's actual capital structure and actual cost rates for long-term debt and preferred stock, and the cost of equity from the utility's most recent fully litigated base rate case.²⁶⁷ If more than 2 years have elapsed between the utility's most recent fully litigated base rate case and the effective date of the quarterly DSIC, then the cost of equity in the Commission's most recent quarterly report on the earnings of jurisdictional utilities is used for the cost of equity component of pretax return.²⁶⁸

These quarterly earnings reports are a monitoring practice first begun by the Commission in 1991 and codified in its regulations.²⁶⁹ Companies quarterly report per book data (unless there is a base rate case pending) and then are permitted to make annualization, normalization, and

²⁶⁵ The model tariff attached to the Final Implementation Order as Appendix A contains the formulas for calculating a DSIC.

²⁶⁶ Code § 1357.

²⁶⁷ Base rate case settlements sometimes include a stipulated ROE that the Commission then uses.

²⁶⁸ Code § 1357(b).

²⁶⁹ Regs. § 71.1.

ratemaking adjustments to its intrastate data to reflect, to the extent practicable, its financial results on a ratemaking basis.²⁷⁰ The Commission’s advisory Bureau of Technical Utility Services then undertakes a current review of market-based ROE by industry segment.²⁷¹ These company-specific results and the comparisons to market returns are reviewed by the Commission and published quarterly.²⁷² The resulting Order establishes a DSIC-allowed return by industry sector. If quarterly adjusted returns exceed the allowed DSIC return, the DSIC is “reset to zero” (i.e., no further DSIC revenues allowed) at least so long as the overearning situation persists.

There are several restrictions and consumer protections included in the DSIC-setting process. Code 1358(a)(1) provides that a DSIC may not exceed 5% of amounts billed for wastewater, 5 percent of distribution rates billed for electric and natural gas (i.e., no gas fuel clause or electric supply revenues), and 7.5 percent of billed revenues for water; however, upon petition, the Commission may grant a waiver of the caps if necessary to ensure and maintain safe and reliable service.²⁷³ Secondly, the DSIC is reset at zero if the company’s return, as reported in the quarterly earnings report, shows that the utility will earn a rate of return that would exceed the allowable rate of return.²⁷⁴

A Section 1308(d) base rate case must be filed within the past five years²⁷⁵ to ensure that a full presentation of the utility’s current revenues, expenses, rate base, and rate of return has been provided to the Commission according to test year concepts. If no base rate case has been filed within that timeframe, the utility must file one to become DSIC eligible.²⁷⁶ As the Commission has recognized, “These provisions ensure that the DSIC process is not used to avoid the comprehensive financial review that takes place in the context of a base rate case.”²⁷⁷

²⁷⁰ Regs. § 71.6.

²⁷¹ Just like in a base rate case. See discussion *infra*.

²⁷² http://www.puc.pa.gov/filing_resources/quarterly_earnings_sum_rpt.aspx.

²⁷³ To date the Commission has done so twice, increasing PGW and UGI to 7.5% in recognition of the pressing need for accelerated improvement/replacement for aging iron and unprotected steel mains and the companies’ commitments to do so.

²⁷⁴ Code § 1358(b).

²⁷⁵ See 66 Pa. C.S. § 1353(b)(4).

²⁷⁶ See 66 Pa. C.S. § 1353(b)(5).

²⁷⁷ Tentative Implementation Order at 12-13.

Finally, Code § 1358(d)(2) requires customer credits for over collections and collections for ineligible projects and charges to customers for under collections. This is standard practice for automatic adjustment clauses under Section 1307 of the Public Utility Code and is also applicable to the DSIC as well.

4. Other Expense Trackers

There has been a proliferation of riders to recover various, mostly legally-imposed, expenses. Among the electric distribution companies' surcharges are: Emergency Energy Conservation Rider, Universal Service Rider, Net Metering for Renewable Customer-Generators, Metering and Billing Credit Rider, Act 129 Compliance Rider, Merchant Function Charge Rider, Smart Meter Rider, and Competitive Enhancement Rider,²⁷⁸ in addition to the DSIC and STAS. Water companies may implement a § 1307 rate for recovery of the company's PENNVEST (state government loans) principal and interest obligations.²⁷⁹

Smart meters are a technology whose time has come as an aid to conservation and grid efficiency. In compliance with the provisions of the smart meter technology portion of Act 129 (Code § 2807(f) and (g)), the Commission directed jurisdictional electric distribution companies with greater than 100,000 customers to submit a smart meter plan for approval.²⁸⁰ Recovery of the capital costs of universal smart meter dissemination is permissible through a reconcilable automatic adjustment clause under Code § 1307.²⁸¹ Costs incurred to implement choice programs may be set as a surcharge under Code § 1307.²⁸² Customer assistance program costs are recoverable.²⁸³ The cost of funding customer energy efficiency and conservation measures is collectable under the procedures of Code § 1307.²⁸⁴ These are but a few examples.

These clauses are also subject to reconciliation and audit.

²⁷⁸ From Tariff Electric Pa. P.U.C. No. 201 (PPL).

²⁷⁹ Regs. § 69.363.

²⁸⁰ *Smart Meter Procurement and Installation*, Docket Number M-2009-2092655, Implementation Order (June 24, 2009).

²⁸¹ Code § 2807(f).

²⁸² Code § 2205(c)(7) (natural gas choice).

²⁸³ Code § 2212(h)(2) (city natural gas distribution operation).

²⁸⁴ Code § § 2806.1(b)(1)(H) (electric distribution company).

5. Revenue Decoupling²⁸⁵

Revenue decoupling²⁸⁶ has been implemented on a limited basis in Pennsylvania but is widely in use across the country. It has been actively debated in several contexts and bears discussion here.

Declining customer usage is a common theme across all utility industries. There are many varied factors driving down sales: conservation, appliance efficiency, customer-owned generation, and demand management, as well as global weather trends. These all have the effect of reducing usage and, therefore, customer bills and utility revenues as well.

Traditional base rate regulation sets prices and allows the utility's revenues to float up or down with consumption. The base rate case invests a lot of time and energy in forecasting those trends that affect revenues and matching them with the rating period. In actual practice, the utility will either over- or under-recover, creating the so-called "throughput incentive"—the incentive to increase sales above the level forecast in the rate case or, at least, not decrease below. Utilities are asked to promote less usage of their product through energy efficiency and conservation programs and, at the same time, to maintain revenues and, therefore, shareholder returns. In this scenario utility financial interests are not aligned with the public policy objectives of efficiency and conservation.

Revenue decoupling, conversely, sets the revenue requirement and then allows prices to rise or fall with consumption. In concept, decoupling allows for regular, incremental adjustments in rates to ensure that the utility collects, or alternatively gives back to customers, the money that was under- or over-collected from the test year revenue requirement because of fluctuations in sales levels. The substantial cost of developing, filing, and litigating repeated rate cases to recognize revenue attrition, a cost funded through rate expense recovery, is likely avoided, or at least minimized, by extending the shelf life of the last rate case decision.

Conceptually, advocates argue, a formula that adjusts rates to compensate for changes in use would continue to provide individual customers with incentives to reduce usage and, at the

²⁸⁵ The research and thoughtful analysis of the Commission's Emerging Leaders is gratefully acknowledged in this section.

²⁸⁶ There are many publications on the topic including this from the Regulatory Assistance Project: <http://www.raonline.org/wp-content/uploads/2016/05/gracefulsystems-morgan-decouplingreport-2012-dec.pdf>.

same time, provide stable revenues for the utility while maintaining revenue opportunities for growth and expansion. Decoupling would also encourage utilities to implement energy efficiency and conservation and eliminate the objection that the opportunities for corporate growth are limited by programs designed to sell less utility services.

Under the “revenue per customer” model, for example, the volumetric rate is calculated by dividing the revenue requirement for each rate class by the number of customers in each rate class, as determined in the utility’s most recent base rate case.²⁸⁷ These volumetric rates are then periodically adjusted to maintain the targeted revenue per customer. This may be the simplest of the decoupling mechanisms to implement and can be designed to recognize and moderate weather risk. A reconcilable § 1307 sliding scale rate would be the legal apparatus.

If implemented on a “full decoupling” basis, all changes in sales are captured and no separate accounting is required for the revenue effects of separate causes. Attempting to isolate weather-driven consumption changes from the effects of conservation is a difficult and ultimately theoretical exercise. Full decoupling is easier to calculate and administer.

The concept is popular nationally, as the Commission noted in its *2006 Investigation Order*:

Such mechanisms have been implemented by some states. It is particularly noteworthy that an eminent environmental advocacy group like the Natural Resources Defense Council would advocate the adoption of ratemaking mechanisms to separate a utility’s margin recoveries from throughput, thereby enabling the utility to aggressively promote conservation programs to help customers reduce their consumption. On the other hand, such mechanisms have also been criticized by various parties. Criticisms include concerns that decoupling mechanisms create more volatile and unpredictable rates and reduce a utility’s incentive to offer innovative services. There are also concerns about public reaction, in part because the concept may be difficult to explain to customers.²⁸⁸

²⁸⁷ 66 Pa. C.S. § 1308.

²⁸⁸ *Investigation of Conservation, Energy Efficiency Activities, and Demand Side Response by Energy Utilities and Ratemaking Mechanisms to Promote Such Efforts*, Docket No. M-00061984, Investigation Order (Oct. 11, 2006) (*2006 Investigation Order*). At least one-half of the states have now implemented some form of decoupling as of this writing.

Revenue decoupling is currently a limited opportunity for EDCs.²⁸⁹ Act 129, as discussed previously, required the electric utilities to reduce energy demand and consumption, but the statute specifies that “decreased revenues...due to reduced energy consumption or changes in energy demand” are excluded from recovery through an automatic adjustment clause and, thus, the issue of this type of revenue loss is limited to a base rate proceeding.²⁹⁰

Consideration therefore has focused on the natural gas utilities. The Commission has reviewed several decoupling proposals in the last 10 years, but only a weather normalization adjustment—a form of single factor decoupling—has been adopted by settlement for two natural gas utilities.²⁹¹ The Commission, otherwise, has twice rejected natural gas company requests to adopt a reconcilable conservation adjustment mechanism, which would have recovered the lost margin that resulted from the companies’ voluntary Energy Efficiency and Conservation programs.²⁹² In the UGI case, the Commission stated:

Moreover, unlike the known and certain Plan expenses to be recovered through UGI’s proposed EEC Rider, the method proposed by UGI to estimate lost revenue lacks the precision necessary for a dollar-for-dollar recovery through the proposed CD Rider or as a regulatory asset. At this juncture, we find that decreased revenue that may result from UGI’s EE&C Plan should be addressed and recovered in a base rate proceeding where appropriate adjustments can be made in the context of actual changes in overall Company revenue and expenses.

The notion of revenue decoupling, however, continues to be studied by Pennsylvania rate makers. On March 3, 2016, the Commission held an *en banc* hearing to seek information from experts on the efficacy and appropriateness of alternative ratemaking methodologies, such as revenue decoupling. The Commission summarized the testimony thusly:

²⁸⁹ Pending legislation may allow EDCs the opportunity to request revenue decoupling.

²⁹⁰ Code § 2806.1(k)(2).

²⁹¹ See, for example, *Columbia Gas of Pennsylvania Inc.*, Docket No. R-2012-2321748, Order (May 23, 2013). This case adopted a Weather Normalization Adjustment that permits the Company to calculate the non-gas portion of customers’ bills based upon normal weather and is applied to all residential customers’ bills for the period October through May. There is a 5 percent dead-band, meaning that there will be no rate adjustment until weather deviates to below 95 percent or above 105 percent of normal weather and the adjustment is to the dead-band threshold only.

²⁹² *Petition of UGI Utilities, Inc. —Electric Division for Approval of its Energy Efficiency and Conservation Plan*, Docket No. M-2010-2210316, Opinion and Order (Oct. 19, 2011) and *Petition of Philadelphia Gas Works for Approval of Demand-Side Management Plan for FY 2016-2020, and Philadelphia Gas Works Universal Service and Energy Conservation Plan for 2014-16*, Docket No. P-2014-2459362, Tentative Opinion and Order (Aug. 4, 2016). EE&C Programs are optional for the natural gas industry.

The utility companies listed above are not, in general, opposed to alternative rate methodologies, however there is consensus among these utilities and several of the advocacy organizations that the current Act 129 programs are working, and they find it difficult to determine the value of any alternative rate methodology reform.²⁹³

That Order also solicited further comment by the parties. The conversation is ongoing.

G. The Base Rate Equation: $RR = E + [ROR (RB)]$

The fundamental principle of base ratemaking is that rates should be set so that a utility has a reasonable opportunity to recover the costs prudently incurred in providing service. The equation: $RR = E + ROR (RB)$ summarizes this principle. The revenue requirement (RR) of a utility equals the expenses (E) incurred, including wages and employee benefits, state and federal taxes and depreciation, plus a return on investment (ROR x RB). The return on investment is calculated by multiplying the overall cost of capital to the company (rate of return or ROR) against the net assets dedicated to the public use (rate base or RB).

The revenue requirement represents the total revenue that a utility needs to collect through the rates charged to the public to cover its cost of service. This is the central issue in a base rate case: identifying the cost of service or revenue requirements of the company.

Suppose Typical Utility Company had the following operating results for 2017:

Typical Utility Company (2017)	
Per Books Operating Result	
1.	Plant and Equipment
	Original Cost
	Less: Depreciation Reserve
	Net Plant in Service
2.	Operating Revenues
3.	Operating Expenses
	Operating and Maintenance
	Depreciation Expense
	Taxes
	Total Operating Expenses
4.	Net Operating Income (Line 2- Line 3)

\$ 5.0 Billion
<u>1.5</u>
\$ 3.5 Billion
\$ 1.5 Billion
\$ 0.8 Billion
0.2
<u>0.2</u>
\$ 1.2 Billion
\$ 0.3 Billion or 8.5% ROR

²⁹³ *Alternative Ratemaking Methodologies*, Docket No. M-2015-2518883, Tentative Order (March 2, 2017).

Typical Utility has collected revenues of \$1.5 billion on a rate base of \$3.5 billion. After paying expenses of \$1.2 billion to vendors, employees, and the like, Typical Utility had \$300 million left over in net operating income.²⁹⁴ This amount available to pay bondholders and stockholders is 8.5 percent (net income/rate base = \$0.3 Billion /\$3.5 Billion). This is the achieved rate of return.

Management of Typical Utility concludes that continuing inflation, new labor contracts, higher capital costs, and plant additions in 2018 will further erode the 8.5% achieved return, despite improved revenues. The company's budget for 2019 is as follows:

Typical Utility Company (2019)
Budget

1.	Net Plant in Service (Rate Base)	\$ 4.00 Billion
2.	Operating Revenues	\$ 2.00 Billion
3.	Operating Expenses	\$ 1.67 Billion
4.	Net Operating Income (Line 2 - Line 3)	\$ 0.33 Billion

Thus, based upon the 2019 budget, net income will provide a return of 8.25 percent (\$0.33 Billion/\$4.00 Billion) without rate relief. Typical believes that the costs of borrowing money and issuing stock to the public are higher. The company's financial officer calculates that the required rate of return necessary to secure new investment money on reasonable terms is 10.5 percent.

Thus, Typical Utility's management decides early in 2017 to file for a rate increase of \$180 million based on the 2019 budget as the fully projected future test year and a 2018 future test year. The amount of the requested rate increase is calculated as follows:

²⁹⁴ This is not "net income" in the traditional accounting sense but income before fixed obligation payments (interest) and payments on preferred and common stock (dividends).

Typical Utility Company (2019)
Proposed Rate Increase

1. Rate Base	\$ 4.0 Billion
2. Required Rate of Return	10.5 percent or 0.105
3. Net Operating Income at Proposed Rates (Line 1 x Line 2)	\$ 420 Million
4. Net Operating Income at Present Rates	\$ 330 Million
5. Income Shortfall (Line 3- Line 4)	\$ 90 Million
6. Income Tax Rate	50 percent or 0.5
7. Rate Relief Requested (Line 5 x 1.5)	\$ 135 Million

Typical's management is advised that rates must be raised \$135 million to increase the company's net income by \$90 million (1.5x due to Federal and State income taxes).

There will be numerous issues raised by the parties. Within reasonable parameters anything claimed in the rate case may be put into issue and contested. The basic categories of issues follow the ratemaking equation include:

- Test Period
 - Validity of Budget and Forecast
- Revenues (RR)
 - Non-Jurisdictional
 - Gain on Property Sales
 - Decline in Sales
 - Non-Recurring Sales
- Expenses (E)
 - Operating and Maintenance Expenses
 - Depreciation Expense
 - Uncollectible Expense
 - Rate Case Expense
 - Taxes
- Rate Base (RB)
 - Future Use
 - Construction Work in Progress

- Depreciation Reserve
- Cash Working Capital
- Materials and Supplies
- Unamortized Balances
- Return (ROR)
 - Capital Structure
 - Cost of Debt
 - Cost of Equity

These elements of the equation and adjustments to them are now discussed.

1. Revenues (RR)

Revenues are not a component of the cost of service *per se*, but rather are employed in determining the revenue increase allowed.

A utility may have several different sources of revenue, some of which are included in rates (“above the line” tariffed services), while others are excluded (“below the line” non-tariffed services). Companies with fuel clauses exclude these revenues since they are not treated in base rates and are reconciled as part of the “E factor” review and audit process. Recognizable electric and gas operating revenues, in addition to regular retail tariff rates, might include sales to other utilities. Sales of appliances, however, would be below the line; excluded from rates on the ground it is a sideline, unnecessary to the provision of utility service. Water companies may be involved in the development and sale of timber or even the sale of the property itself, which would become a revenue issue in a rate case. A utility may collect rent from property claimed in rates, producing revenues that should be imputed to ratepayers.

In addition to these controversies, several test year issues are also presented. First, sales must be normalized to exclude abnormal weather conditions occurring during the test year. For example, gas utilities are extremely weather-sensitive and, if a colder-than normal winter has occurred during the test year, creating higher-than-normal sales, reflecting high sales volumes will set rates too low. The converse is true of warmer-than-normal weather. Thus, the companies

are required to compute a normal level of degree days (i.e., normal temperature)²⁹⁵ using a period of years, typically 10-to 30-year averages.²⁹⁶

Second, any rate increases received during the test year must be factored into the test year (i.e., annualized) as if the rate change had been in effect all year. Next, if a year-end rate base or year-end expenses are employed, the number of customers and sales might be adjusted to a test year end level also to prevent a mismatch. Finally, any changes occurring outside the historic test year that are “known and measurable” (e.g., a new industrial customer moved into the service territory) may be recognized. If a future test year is employed, the focus shifts to whether the company’s budgeted sales are reasonable and accurate.

2. Expenses (E)

As with revenues, expenses may be “below the line” (non-recoverable) or “above the line” (chargeable to ratepayers). For example, receipts from appliance sales were excluded from our discussion above and so too would be any related expenses. Payments to affiliated companies, if the price is high compared to the prevailing market for the service or good provided, will be excluded to the extent excessive.²⁹⁷ The normal test year adjustments (e.g., normalization, amortization, out-of-period) should also be performed. Some more typical types of expenses are discussed below.

a) Operating and Maintenance (O&M) Expenses

O&M expenses are usually the largest category of base rate expenses, as these expenses encompass all reasonable and normal expenses incurred to provide regulated service. For example, O&M expenses include the cost of labor and expenses associated with the transmission and distribution of electricity; production, storage, and distribution of gas and water; customer service; sales expenses; and administrative and general office expenses. The items claimed must

²⁹⁵ Heating degree days measure temperature below 65°F, and cooling degree days are those above that level. https://www.eia.gov/Energyexplained/index.cfm?page=about_degree_days.

²⁹⁶ This issue has become more controversial with the progression of global warming and fewer very cold winters. <https://www.epa.gov/climate-indicators/climate-change-indicators-heating-and-cooling-degree-days>. An energy utility typically will seek a shorter normalization period to eliminate earlier periods of colder weather from the calculation. The concept of revenue decoupling, as a solution to this forecasting problem, is discussed earlier in this handbook.

²⁹⁷ Affiliated interests are closely regulated by the PUC. Any sale of service or equipment to a utility by a related company must be approved by the Commission beforehand. Code § 2101, *et seq.*

be reasonable and necessary; therefore, if expenses are not incurred, are imprudently incurred, or are abnormally overstated during the test year, they should be adjusted or disallowed and not recoverable through rates. The usual test year analysis also applies to this class of expenses.

b) Depreciation Expense²⁹⁸

Investors provide the capital funds to pay for the installation of the facilities or plant necessary to provide service. Broadly speaking, depreciation is the loss, not restored by current maintenance, which is due to all factors causing the ultimate retirements of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence. Annual depreciation is the loss that takes place in a year.²⁹⁹ The cost of service is not only a fair return *on* the investment but also includes a return *of* that investment over the plant service life.

The capital employed to purchase utility plant is recovered from ratepayers through depreciation expense (i.e., the return of investment) that is accumulated over the life of the asset. There are two objectives to be met in computing the depreciation expense: (1) to recover the cost or depreciable base over the service life; and (2) to charge in each accounting period a measure of the capital being recovered. The idea is to match the service life of the asset to the recovery period.

For example, Typical Utility borrows the money to purchase a \$100,000 widget, a necessary item of operation. Widgets, on the average, last 5 years before they break down and cannot be used anymore, rendering them valueless.³⁰⁰ Therefore the depreciation expense on the widget is \$20,000 per year (\$100,000/5 years) using “straight-line” depreciation (discussed in a

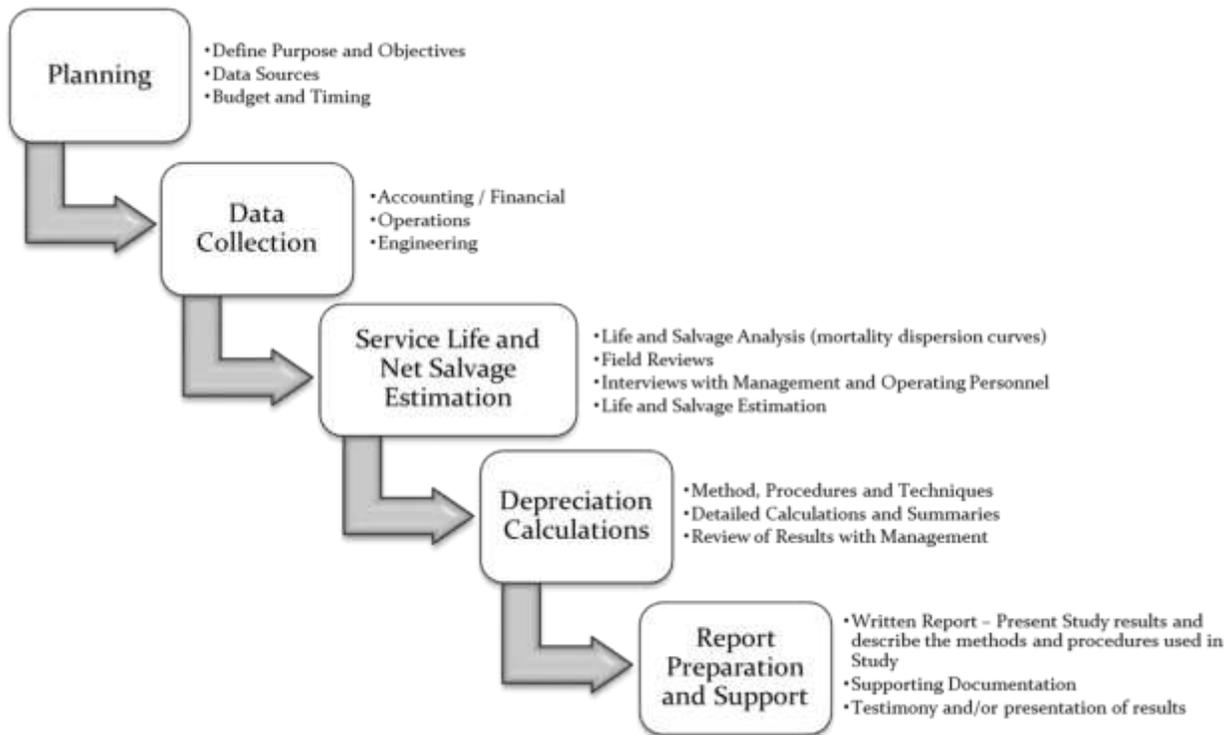
²⁹⁸ Two excellent books about depreciation are: *Engineering Valuation and Depreciation* by Marston, Winfrey and Hempstead (1953) (Iowa State University Press, South State Avenue, 112C Press Office, Ames, Iowa 50010; \$13.50) and *Public Utility Depreciation Practices* compiled and edited by Staff Subcommittee on Depreciation of The Finance and Technology Committee of the National Association of Regulatory Commissioners (1996) (Available by contacting NARUC).

²⁹⁹ *Introduction to Depreciation and Net Salvage of Public Utility Plant and Other Industries*, Edison Electric Institute, May 2003, p. 5.

³⁰⁰ Although, in the text example above for purposes of simplicity, our hypothetical widgets are totally expended and without value or cost after 5 years, any positive salvage value that property might have at the end of its useful life or negative salvage (e.g., removal or decommissioning costs) would be deducted from or added to the book depreciable value to prevent double recovery by the utility. As a general rule in Pennsylvania, net salvage costs are not prospectively considered in depreciation expense. *Penn Sheraton Hotel v. Pa. PUC*, 184 A.2d 324 (Pa. Superior 1962). The amount of net salvage built into rates is a 5-year historic average of net of salvage received and the cost of removal incurred at the time of the rate filing. The unamortized balance, positive or negative, of net salvage is reflected in rate base.

moment). At the end of the 5th year, \$100,000 has been collected for repayment back to the original investors. As the depreciation expense is recovered each year, its cumulative sum is deducted from the rate base value as a “depreciation reserve” so that a return will no longer be earned on the amounts expended.

Large investor-owned utilities establish depreciation rates using depreciation studies. Studies are submitted to the Commission by utilities as part of general rate filings and are normally completed every five years. Depreciation experts will define the life (including the pattern of retirement of the group) and the net salvage in a depreciation study.³⁰¹ After those two parameters are defined, the rest (calculating the depreciation expense and depreciation rates) is simply a mathematical exercise. The following is a simplified depreciation study flow chart:



Parameters estimated from service life studies are integrated into an appropriate formulation of an accrual rate, and ultimately the depreciation expense, based upon a selected depreciation system. Three elements are needed to describe a depreciation system: a method, a procedure, and a technique. A depreciation system is therefore formed by selecting an element so

³⁰¹ As indicated previously, under Pennsylvania rate regulation practices, experienced net salvage is amortized after its occurrence. Therefore, no adjustments for expected salvage are made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering net salvage is based on the amortization of net salvage over a 5-year period.

that the system contains one method, one procedure, and one technique. A depreciation method (e.g., straight-line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (e.g., average service life) identifies the level of grouping or sub-grouping of assets to obtain composite life statistics for an account. A depreciation technique (e.g., remaining life) refers to the portion of the average service life used in the depreciation calculation. The majority of depreciation studies submitted by utilities under Commission jurisdiction employ the straight-line method, the remaining life basis, and either the average service life (ASL) or the equal life group (ELG) procedure when calculating the depreciation accruals for most plant accounts.

The straight-line depreciation method is employed by the Commission.³⁰² This method provides that the cost of the property is allocated into equal amounts over the estimated life of the asset, called the “service life.” Obviously, the depreciation on each widget, utility pole, and pipe is not individually calculated.

In order to fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve that is plotted as a percentage of the units surviving at each age. The survivor curve represents the percentage of property remaining in service at various age intervals, much like an actuarial (mortality) study. Iowa survivor curves are simply statistics based upon engineering estimates developed in a study at the University of Iowa in the 1930s and revalidated in the 1970s as being representative of physical plant mortality.³⁰³

The useful life may be subsequently adjusted should the initial estimate prove too short or too long. The curves provide a tool to estimate the average service lives of plant in service so that depreciation accruals can recover the investments over the actual useful lives of the assets.

³⁰² As compared to “accelerated” depreciation, which measures the rate of depreciation over a shorter timeframe than a straight line or on a curve, usually front end loaded. The effect is a faster rate of capital recovery. This is often used in taxation to promote capital investment, where depreciation is a deductible expense.

³⁰³ *Life Characteristics of Physical Property*, Robley Winfrey and Edwin Kurtz, Volume 103 of Bulletin (1953, Iowa Engineering Experiment Station); *Revalidation of Iowa type survivor curves*, John George Russo (1978, Iowa State University) (available online at <http://lib.dr.iastate.edu/cgi/viewcontent.cgi?article=7518&context=rtd>).

An estimate of service life is made first, and then an apportionment of depreciation expense is assigned to each year or accounting period so that the total cost will be recovered over that estimated life. Generally, the depreciation base, adjusted for any estimated net salvage, is used as the total sum to be recovered. In the straight-line method of depreciation, as used by the Pennsylvania Commission, the estimated life is used as a divisor to determine the dollars to be charged as depreciation expense. The rate is held constant, and changes are made only when revised estimates of life or salvage are accepted.

The selection of the proper curve fit to any USOA plant account is an art, not a science. The guesswork can be minimized by objective statistical studies, comparative analysis with like plant, and periodic reviews to produce reasonably accurate results, particularly where large numbers of units of plant are involved. Because the end answer is necessarily still an estimate of the future, the use of some form of periodic review has become accepted practice in most depreciation work. Furthermore, remaining service lives cannot always be equated with advancing age, because factors causing retirement do change and estimates made at one time may no longer hold true a few years later.

Now for a closer look at the straight-line method. It is based on charging a like amount ratably each year or accounting period over the service life of a plant item or plant group. It thus directly meets both depreciation objectives, which perhaps accounts for its wide acceptance in utility practice. The basic formula is:

$$\text{Annual Depreciation Accrual} = \frac{\text{Depreciable Cost}}{\text{Service Life}}$$

This may be applied either under a “Whole Life” Method (sometimes referred to as the Average Service Life or Total Life Method) or a “Remaining Life” Method as follows:

In the Whole Life Method, the original or gross plant cost is used as the depreciable cost, and an average life is used in the denominator. The formula is:

$$\text{Annual Depreciation Expense} = \frac{\text{Original Cost of Plant}}{\text{Average Service Life (years)}}$$

In the Remaining Life Method, the net plant or book cost of currently surviving plant less book depreciation reserve is used as the depreciable cost, and a remaining life or average future service expectancy is used in the denominator. The formula is:

$$\text{Annual Depreciation Expense} = \frac{\text{Original Cost of Plant} - \text{Depreciation Reserve}}{\text{Average Remaining Life (years)}}$$

In actual practice, a depreciation rate expressed as a percentage is desired rather than depreciation accruals. For the Whole Life method, the following formula is used:

$$\text{Annual Accrual Rate} = \frac{\text{Original Cost of Plant (i.e. 100\%)}}{\text{Average Service Life (years)}}$$

For the Remaining Life Method, it is common to determine indicated annual accruals as described above and then to apply the following formula to arrive at the depreciation rate in percent:

$$\text{Annual Accrual Rate} = \left(\frac{\text{Annual Depreciation Expense}}{\text{Original Cost of Plant}} \right) \times 100$$

This rate may also be derived by dealing entirely in percentages as follows:

$$\text{Depreciation Rate} = \frac{\text{Original Cost of Plant (i.e. 100\%) - Reserve \%}}{\text{Average Remaining Life (years)}}$$

In general, Pennsylvania uses the Remaining Life Method to determine depreciation expense and the depreciation reserve.³⁰⁴

The depreciation rate will be modified with a change in estimated service life or salvage at the time of periodic review. Changes in service life will ordinarily result in a more pronounced change in the depreciation rate under the Remaining Life Method as compared to the Whole Life Method. The Remaining Life Method therefore relates depreciation to different time periods than the Whole Life Method.

c) Uncollectible Expense

Another item allowed by the Commission is uncollectible expenses—the unpaid bills of customers who have received service but cannot or will not pay the company. This collection problem is especially acute for urban utilities. For example, PECO Electric claimed almost \$57 million for uncollectible accounts, mostly residential, in its 2015 rate case. While the PUC maintains a very detailed customer bill of rights as protection against unwarranted utility practices and severely restricts termination of customers during the winter, these measures are

³⁰⁴ *Pa. PUC v. Philadelphia Suburban Water Company*, 61 Pa. PUC 328 (1986).

not without cost. There also are a multitude of customer assistance programs designed to provide financial help to those in need. These assistance-related expenses are also recovered in rates.³⁰⁵

d) Rate Case Expense

Rate case expense is the incremental, out-of-pocket cost to the utility of applying for and litigating, if required, a base rate increase.³⁰⁶ There are two views on the question of whether consumers should pay for this item. Opponents find it an ironic injustice that ratepayers must pay all or even some of the costs of having their rates raised. Proponents argue that rate case expense is a cost of doing business imposed by the state and therefore a legitimate operating expense. Further, they argue that rate increases are necessary to attract the capital required to meet increasing consumer demand for service.

The Commission's practice is to recognize all prudently-incurred rate case expense and set a normalization period based upon historic filing frequency.³⁰⁷ So, if Typical Utility's history in the 2018 filed case shows previous base case filings in 2013, 2008, and 2003, then the normalized rate case expense for a case costing Typical Utility a total of \$100,000 would be \$20,000 per year (\$100,000/5 years).

e) Taxes

Public utilities in Pennsylvania are subject to:

- Federal Income Tax (currently) is 21 percent of federal taxable net income;
- State Corporate Net Income Tax (CNI) is levied at the rate of 9.99 percent on state taxable income;
- Public Utility Realty Tax (PURTA) is a tax, with a rate that is set annually, on all real property and structures located in Pennsylvania owned by a utility, excepting those furnishing sewage services. The PURTA tax base is the fair market value of utility realty; and

³⁰⁵ A listing of customer financial aid programs can be found at:
http://www.puc.state.pa.us/consumer_info/electricity/energy_assistance_programs.aspx.

³⁰⁶ The rate case expense claimed is only part of the cost of filing if the company prepares its rate cases "in house" by permanent employees whose paychecks are already included in the cost of service as an administrative expense. Rate case expense refers only to the cost of any services performed outside the company, including copying, mailing, professional printing, expert witnesses, lawyers, fees, travel, and the like. Utilities widely differ in their use of professional witnesses. In-house services are generally cheaper, although for rate-setting purposes, annual in-house costs are recovered 100 percent.

³⁰⁷ *City of Lancaster v. Pa. PUC*, 793 A.2d 978 (2002).

- State Gross Receipts Tax (GRT) is imposed upon the gross receipts received from sales of utility services and varies by type of service for various historic reasons. The electric rate is 5.9% and telecommunications is 5 percent. Natural gas and water utilities are exempt.

Taxes cause an upward spiral in utility rate increases when the GRT and income taxes are placed upon the revenue and income allowed by the PUC. Several significant tax issues potentially exist in a rate case.

The premier income tax issue is normalization of accelerated depreciation benefits. Depreciation, like any other expense, is tax deductible. To induce greater corporate cash flow and to free up capital for investment in plant and equipment, large depreciation deductions for tax purposes are allowed in the early years of the useful life of an asset. Both federal and state governments allow a company to write off an asset (depreciate it) more quickly relative to straight-line, thus reducing taxes in the early years (because expenses, including depreciation expense, lower taxable income).

Consider Typical Utility’s \$100,000 widget that is projected to last 5 years and its relationship to income tax payable:

Depreciation Deduction (\$ in thousands)			
Year	Straight line	Accelerated	Difference in Tax Liability (at 50% Tax Rate)
1	\$20	\$40	\$(10.00)
2	20	30	(5.00)
3	20	15	2.50
4	20	10	5.00
5	20	5	7.50
	\$100	\$100	\$0.00

Thus, a tax deferral or temporary tax “savings” (total of \$15 in Years 1 and 2) is generated in the early years of the asset, producing cash for investment. In the later years of the investment, larger taxes are due (the \$15 is paid back in Years 3-5). Using this model, the taxes paid under either approach are the same because of higher taxes toward the end of the asset’s life.

The controversy on this issue is whether the taxes should be normalized for ratemaking purposes (that is, based on book income as opposed to actual taxes paid) when accelerated

depreciation is employed on the tax return. If income tax normalization is employed, proponents argue, the utility enjoys the savings from the lower tax liability during the early years of the asset's life, but must pay the higher taxes at the end. Thus, income tax normalization costs the consumer no more over the life of the asset, and, in fact, is favorable because it internally generates capital. Others believe that income tax savings related to accelerated tax depreciation should be "flowed through" to ratepayers, arguing that the higher taxes are never paid at the end of the life of the asset, because new depreciable assets are always being added, and therefore "phantom taxes" are built into rates.

Normalization is required by federal income tax laws for a utility to be able to claim accelerated tax depreciation. Generally, the Commission's current policy is to use normalization for federal income tax purposes and the flow through method for state income tax purposes.

A second common tax issue is consolidated tax savings. Taxation authorities allow an affiliated group of companies (e.g., a combination of utility company, sister corporations, and the parent) to file a single tax return at the parent company level for federal taxes. These unregulated affiliates (e.g., natural gas exploration or electric generation) may generate little or no income and therefore generate no tax or even tax credits. Thus, the consolidated entity may pay little or no income taxes on an aggregate basis. However, on a "stand alone" basis, a utility affiliate that participates in the consolidated tax return may claim taxes at the full rate (50%) in the rate case, collecting for taxes that they may not pay on a consolidated basis. The consolidated tax savings adjustment was adopted by the Commission, affirmed under a 1985 Pennsylvania Supreme Court decision,³⁰⁸ and applied consistently for almost 30 years thereafter.

Act 40, signed into law and effective on Aug. 11, 2016, however, amended the Code to require that, "income tax deductions and credits, including tax losses of the public utility's parent or affiliated companies, shall not be included in the computation of income tax expense to reduce rates."³⁰⁹

A third tax issue is hypothetical interest expense. Interest is income tax deductible. The more interest paid to investors, the lower the income taxes a utility must pay. Equity earnings, on the other hand, are fully taxable. Thus, the amount of debt outstanding (upon which interest must

³⁰⁸ *Barasch v. Pennsylvania Public Utility Commission*, 507 Pa. 561, 493 A.2d 653 (1985).

³⁰⁹ Code § 1301.1. The statute further provides that 50 percent of the rate increase goes to support reliability or infrastructure investment and 50% for general corporate purposes.

be paid) is not only a rate of return issue (as discussed later) but a tax issue also. Consider the following three utilities with the same rate base, income, and tax rate, but different capital structures:

	Utility A	Utility B	Typical Utility
Debt	\$0	\$25	\$50
Equity	\$100	\$75	\$50
Rate Base	\$100	\$100	\$100
Net Income	\$20.00	\$20.00	\$20.00
Interest Expense (10%)	0.00	2.50	5.00
Taxable Income	\$20.00	\$17.50	\$15.00
Tax Rate	50%	50%	50%
Income Tax Due	\$10.00	\$8.75	\$7.50

The interest rate (10 percent or 0.10) is multiplied against the amount of the debt in the capital structure. The interest expense is then subtracted from net income to arrive at taxable income. Typical Utility, identical in all respects to the other two companies, except with a reasonable ratio of debt-to-equity, has a lower income tax. It is the policy of the PUC to employ a hypothetical interest expense where a hypothetical capital structure is imposed.

3. Rate Base (RB)

A utility is entitled, as a matter of U.S. Constitutional law, to earn a fair return on the value of its property. However, utility property is included in rates only if prudently constructed, necessary and operational (i.e., "used and useful") to the provision of service. The usual test year issues of normalization, amortization and out-of-period adjustments, as well as year-end vs. average year apply here. The valuation of rate base is established by engineering, accounting and legal concepts. Typical valuation issues are discussed below.

a) Original Cost

The Code specifies that the rate base of the utility "shall be the original cost of the property when first devoted to the public service less the applicable accrued depreciation as such depreciation is determined by the commission."³¹⁰ The original cost standard, however, was not always the law in Pennsylvania.

³¹⁰ Code § 1311(b).

The proper valuation of utility property has had a controversial history in the Commonwealth, toggling between hybrids of “original cost” and “reproduction cost” techniques. Reproduction value, as the name implies, is an appraisal of the utility’s property under present prices. Advocates argue that this method recognizes inflation and the resultant loss of money’s purchasing power. Proponents of original cost, on the other hand, argue that use of reproduction cost resulted in a windfall to investors by compensating them beyond their original investment and point to the difficulty of establishing a proper trending technique. Rates can vary substantially depending upon the valuation technique used.³¹¹

For many years, the PUC employed a composite of the two methods labeled “trended original cost”, which was neither original nor reproduction cost, but something in between. In practice, the Commission calculated cases on an original cost basis and then backed into the fair value and rate of return findings that replicated the original cost result. In 1981, the Commission successfully convinced the Pennsylvania Supreme Court that the statutorily-required “fair value” could include strictly original cost valuation and the burdensome reproduction cost standard was abandoned.³¹²

The practice of using original cost exclusively was codified shortly thereafter under Act 153 of Sept. 27, 1984 (P.L. 721).³¹³ This statutory prescription modified the previous version of Section 1311, which had stated, “The Commission may, after reasonable notice and hearing, ascertain and fix the *fair value* of the whole or any part of the property of any public utility” (emphasis added).³¹⁴ Original cost is now the law of Pennsylvania.

b) Alternatives to Original Cost

As discussed previously in the water operations section of this Handbook, it has long been the policy of the General Assembly and this Commission to encourage the consolidation of small water and waste water systems. This includes liberalization of rate base valuation rules beyond strict original cost principles for the acquiring company.

³¹¹ See, for example, discussion in *Keystone Water Co. v. Pa. P.U.C.*, 19 Pa.Comm. 292 (1975).

³¹² *Pa. P.U.C. v. Pennsylvania Gas and Water Co.*, 492 Pa. 326, 424 A.2d 1213 (1981) although, as the original handbook suggested, a subsequent Commonwealth Court decision re-muddied the waters. *Pennsylvania Gas and Water Co. v. Pa. P.U.C.*, Pa. Cmwlth., 456 A.2d 1126 (1983).

³¹³ Code § 1311(b).

³¹⁴ *Popowsky v. PA. P.U.C.*, 150 Pa. Cmwlth. 166, 615 A.2d 857, (1992).

The price to buy a utility operation may be greater than its original cost, less depreciation, as the market value of a going concern often exceeds the sum of its parts. According to regulatory (and general) accounting precepts, however, plant-in service assets (e.g., hard assets, like buildings and equipment) can be stated on a company's balance sheet only according to book value. This sometimes creates problems for companies with a fair market value that exceeds the depreciated original cost of plant (or book value).

An acquisition adjustment is the premium paid for acquiring a company that represents more than its tangible assets or book value. Much consideration has been given to awarding the acquiring entity this higher value in rate base where public interest policies are served. The essential issue is to identify the benefits that would be received by customers due to the purchase at the higher value.

There are two instances, both involving the water and wastewater utilities, where higher-than-depreciated original cost values can be placed into rate base. Code § 1327 offers a rate base valuation equal to the acquisition cost to public utilities acquiring small "troubled" water and wastewater companies, private or municipal.³¹⁵ The Commission has promulgated several rules that effectuate this provision under the Commission's regulations.³¹⁶

The second, more recent method, enacted under Act 12 of 2016, allows the buyer of municipally-owned water and wastewater systems to include the "fair market value" of the acquired property in rate base.³¹⁷ Adverse operating conditions for the acquired company need not be present. The fair market valuation process requires both the buyer and the selling municipal corporation or authority (seller) to engage the services of a licensed engineer to assess the tangible assets of the seller. The buyer and seller are also required to each engage a utility valuation expert to determine the fair market value of the assets. The Commission maintains a list of utility valuation experts from which the buyer and seller must choose. Pending the

³¹⁵ The acquired entity must serve 3,300 or fewer customer connections, be distressed, and "...not, at the time of acquisition, furnishing and maintaining adequate, efficient, safe and reasonable service and facilities..." Code § 1327(a)(3).

³¹⁶ Regs. § 69.711.

³¹⁷ Code § 1329.

implementation of final regulations, the Commission entered a Final Implementation Order on Oct. 27, 2016.³¹⁸

c) Plant Held for Future Use

Utility companies often include the cost of property that is not currently being used but which it asserts will be used in the near future. Such property is usually in the form of land or land rights to be used for some relevant purpose (e.g., a pumping station or transmission line). The company obviously must acquire the necessary parcels of land before it can construct the needed facility. This is particularly true for the kinds of projects that require a long construction period.

Occasionally other parties to the rate case will attack the company's claim for plant held for future use, arguing that the company does not have a definite plan for the property in question or that, due to errors in the company's forecasts, the planned facility will either not be needed or will be postponed beyond the near-term.

The Commission generally will not permit the inclusion of such property in rate base unless the company can demonstrate a need and a definite plan to build within 10 years. The ten-year rule is not rigid, and the Commission has permitted some deviation in the past.

d) Depreciation Reserve

The original cost of the company's rate base is reduced by the amount of accumulated depreciation (depreciation reserve). As discussed in the Depreciation Expense section above, ratepayers pay for the annual depreciation of the company's plant as an ongoing expense. Where the company and its investors have already been compensated for the original investment via depreciation (partial or complete of an asset) through depreciation expense, investors should not earn a return on that amount. For example, consider the accounting treatment of Typical Utility's \$100,000 widget with a useful life of 5 years:

³¹⁸ *Implementation of Section 1329 of the Public Utility Code*, Docket No. M-2016-2543193, Final Implementation Order (Oct. 27, 2016). The Commission has a website page on § 1329 at: http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/section1329_applications.aspx.

End of...	Year 1	Year 2	Year 3	Year 4	Year 5
Rate Base (\$ in thousands)	\$100	\$100	\$100	\$100	\$100
Depreciation Expense	20	20	20	20	20
Accumulated Depreciation	20	40	60	80	100
Net Rate Base	\$80	\$60	\$40	\$20	\$0

As ratepayers pay for the consumption of the widget through depreciation expense, the rate base value of the widget (and the return on that investment) declines and at the end of the widget's useful life is fully depreciated (i.e., valued at zero). If the company accurately records annual depreciation expense and the corresponding accumulated depreciation, the book value and, correspondingly, the return on the investment, will decline over the life of the asset.

e) **AFUDC and CWIP**

Regulators have generally excluded construction projects from rate base, citing the “used and useful” rule to require that the plant must be online and in service (or very soon to be) before inclusion in rate base. Construction projects therefore are temporarily “below the line”, and the related costs are not collected from ratepayers. Since interest and dividends must be paid during construction, whether funded by ratepayers or not, these costs are refinanced.³¹⁹ The utility borrows more money and/or sells more stock to pay interest on previously incurred debt and dividends on outstanding stock. Therefore, the utility company must not only pay the cost of purchasing and installing the bricks and mortar comprising the plant but must also pay capital costs.

Recognizing, however, that the construction financing is a real and unavoidable cash expense, regulators have established an accounting category called Allowance for Funds Used During Construction (AFUDC) that is designed to reflect these financing costs on a deferred basis. Consider Typical Utility which builds a \$50,000,000 distribution facility over 5 years with an overall cost of capital of 10%. Typical Utility raises the capital externally in the market (by

³¹⁹ Think of a construction loan on a house. Interest is paid on the draws during construction and then rolled into a long-term mortgage. This is similar.

incurring debt, such as bank loans or bonds, or by selling equity securities, such as preferred or common stock) and internally from retained earnings.³²⁰

The original cost valuation of the new facility includes both the bricks/mortar and the financing charges incurred during construction.

Typical Utility Cost of Plant (with AFUDC) (in million \$)						
End of...	Year 1	Year 2	Year 3	Year 4	Year 5	
1. Cost of Bricks and Mortar	\$10	\$10	\$10	\$10	\$10	\$10
2. Construction Balance (from previous year)	\$0	\$11	\$23	\$36	\$51	
3. Total to Date (1+2)	\$10	\$21	\$33	\$46	\$61	
4. Overall Cost of Capital	10%	10%	10%	10%	10%	10%
5. Total Financing Costs (3x4)	\$1	\$2	\$3	\$5	\$6	
6. Construction Balance (3+5)	\$11	\$23	\$36	\$51	\$67	

Thus, the completed rate base value of Typical Utility's new distribution facilities will be \$67,000,000. Of that total, \$17,000,000, or 34 percent of the cost of the plant, represents AFUDC (sum of line 5), the amount of money paid to investors during the construction phase, which has been refinanced by the utility. The \$17,000,000 in AFUDC, as well as the \$50,000,000 cost of the plant, will be recouped from customers over the life of the asset through depreciation expense and a return provided on the undepreciated balance.

This financing burden, if the plant being constructed is large enough relative to the company's size, can create cash flow stress, so that the cost of construction capital becomes expensive or the company's ability to borrow is jeopardized.

The alternative is to include all or part of the construction work in progress (CWIP) balance in rates before the plant is completed. The financing costs incurred during construction would not be refinanced, but would be recovered currently. The essence is the source of money to pay the investor's demand for a cash return during the construction period.

³²⁰ Retained earnings are generally inadequate to fund construction because of the limits placed on utility earnings and the high payout-ratios (the amount of earnings paid to investors as dividends). Utilities therefore are dependent upon the capital markets.

The same transmission plant construction rate recovery would look like this:

Typical Utility Cost of Plant (with CWIP) (in million \$)						
End of...	Year 1	Year 2	Year 3	Year 4	Year 5	
1. Cost of Bricks and Mortar	\$10	\$10	\$10	\$10	\$10	
2. Construction Balance (from previous year)	\$0	\$10	\$20	\$30	\$40	
3. Total to Date (1+2)	\$10	\$20	\$30	\$40	\$50	
4. Overall Cost of Capital	10%	10%	10%	10%	10%	
5. Total Financing Costs (3x4)	\$1	\$2	\$3	\$4	\$5	
6. Collected in Rates	\$1	\$2	\$3	\$4	\$5	
6. Construction Balance (3)	\$10	\$20	\$30	\$40	\$50	

Under this simplified example, the rate base value of Typical Utility's 750 KV transmission line, when complete, is \$50,000,000. Under this model, ratepayers paid \$15,000,000 of interest (sum of line 6) during the construction period instead of the \$17,000,000 paid under the AFUDC method.³²¹

To summarize, customers always pay for capital costs during the construction period under either the AFUDC method or the CWIP method. The difference is when the capital costs are recovered. Under the AFUDC model, all the construction costs, financial and otherwise, are deferred, and the customers who receive service from the new transmission line pay when the new facilities come online (e.g., when it is used and useful). Under the CWIP method, current customers who receive no current benefit from the plant pay the financing costs.

There are arguments to support both sides of this issue. Those opposed to CWIP argue that: (1) while the rate base is ultimately larger, the higher rates can be paid in cheaper inflated dollars; (2) consumers should not be forced investors in the company; (3) some customers (especially older ones) may never get the use of what they paid for; and (4) inclusion of CWIP

³²¹ This is a simplified example. A more sophisticated "present value analysis" would be used to determine the costs to the ratepayer over the life of the plant under each method. Moreover, in actual application, the \$15,000,000 collected in rates would reduce the need for external financing, thereby resulting in a lower cost of capital when compared to the AFUDC method.

eliminates any incentive for utilities to be economical in their construction programs, thus encouraging waste and unnecessary building.

Proponents of the CWIP method argue that: (1) consumers are saved money in the long run; (2) needed plant additions can be financed; (3) the cost of necessities of life will be equally inflated later, so there will be no saving in waiting to pay the costs in cheaper dollars; (4) that, for the most part, today's customers are tomorrow's customers, and they are causing the need to build new plants by present and increasing demand; and (5) if a plant has a higher cost because of excluding CWIP, succeeding insurance costs and a number of state taxes will be higher than otherwise over the 30-40 year life of the plant. And so, the controversy continues.

The policy of the PUC toward CWIP has several facets. Short-term CWIP (i.e., construction that will be completed within a short time (6 months) following the end of the historic test year) is generally includable in rate base, because AFUDC may no longer be accumulated after the plant is completed and no substantial cost is shifted to ratepayers. With the advent of the fully projected future test year, this issue has not arisen, because the FPFTY ends twelve months after rates have become effective.

However, the PUC does not allow major, long-term construction projects into rate base until completed and online. The most vigorous debate of this issue has historically been in the electric sector concerning generation plant construction. Code § 1315 (Act 335 of 1982) sets up a prohibition against the inclusion of CWIP in electric company rate base. Unless serving an environmental or safety purpose, "the cost of construction or expansion of a facility undertaken by a public utility producing, generating, transmitting, distributing or furnishing electricity shall not be made a part of the rate base nor otherwise included in the rates charged by the electric utility until the facility is used and useful in service to the public [defined as "presently providing actual utility service to the customers"]."

Undoubtedly, the widespread use of the DSIC mechanism and the prompt inclusion of new construction into rates without the lag of a base rate case has lessened the amount of new plant that is not rate recognized.

f) Cash Working Capital

Cash working capital provides the current or day-to-day expense needs. It is the amount of dollars that a public utility needs to have on hand at any moment in time to meet financial

obligations or, stated another way, the amount of liquidity needed to meet short-term obligations. For the individual, it is the checking account balance you need to live on between paychecks. Cash working capital is included as an element of rate base.

The amount of cash working capital should be sufficient to cover the lag between day-to-day operations expense payments and receipts of cash through rates from the company's customers. Billing cycles are mostly monthly, and bills are issued after service is provided and measured. The lag in customer payment encompasses the service period itself (usually one month), meter reading time, bill process time, and the lag in payment from the customer.

The method of determining cash working capital varies with the size, nature, and operation of the utility. There are two common approaches to calculating cash working capital that are accepted by the Commission. The simplest is the "FERC formula" method (or 45-Day Rule), commonly referred to as the "one-eighth method," The more complicated is a "lead/lag" study.

Lead/lag studies determine the amount of cash required to cover the gap between cash expenditures made to render service and the receipt of revenues from sales of those services. Lead time is the number of days between the company's receipt and payment of invoices it receives. Lag time is the average number of days between the company's billing of its customers and its receipt of related revenues. The Commission requires all utilities proposing a revenue increase exceeding \$1,000,000 to submit a detailed lead/lag study in support of any cash working capital claim.³²²

For smaller utilities, the detailed study of lead/lag is costly and impractical. The one-eighth method is so named because it assumes an average net lag of 45 days (45 days/365 days = 1/8) which is then multiplied by the total operating and maintenance expense, less purchased gas, water, or electric (depending on utility filing type); non-cash items such as depreciation and uncollectibles; and taxes, since the taxes are collected prior to payments being made. The resulting figure is then included in rate base.

³²² Regs. § 53.53.

g) Materials and Supplies

Most, if not all, utility companies maintain an inventory of recurrently-used materials and supplies to ensure timely repair and replacement. In the case of electric companies, for example, the company must keep a supply of meters, transformers, conduit, etc. on hand for immediate use. The non-inventory materials and supplies used for routine property maintenance are generally expensed, and the materials and supplies inventory discussed in this section represents a capital investment, or improvement to property.

A reasonable level of materials and supplies inventory has historically been recognized in rate base and permitted to earn a return. To eliminate the impact of unusually large investments in materials and supplies at any one point in time, such as the end of the test year, the Commission has generally employed a method of averaging thirteen months of inventory balances to determine a reasonable allowance.

h) Unamortized Expenses

As described previously, amortized expenses are those expenses that, because of their unusual nature or some other reason, are recovered over an extended period. Whether the unamortized (unrecovered) balance of an amortized expense should be claimed in rate base can be a disputed matter in base rate case proceedings. The utility will assert that it has paid the full amount, and its investors, who supplied the cash, require a return on that expenditure. The policy of the PUC is to exclude such balances from rate base, forcing the utility to absorb the financing costs of the unrecovered balance, recovering only the annual expense amount.

i) Customer Contributed Capital

Customers are required to pay upfront fees to a utility under two common circumstances. First, contributions in aid of construction (CIAC) are tariff-imposed, non-refundable customer payments for new or expanded service, such as a line extension that exceeds the maximum obligatory distances and is deemed uneconomic (usually a ratio of capital cost to expected revenues over a reasonable period). The second, a customer deposit, is required as a condition of new or continued service for customers with a low credit or poor payment history (frequently two months of service). These payments represent capital available to the utility for cash working capital or investment and are deducted from rate base.

j) Regulatory Assets

Accounting Standards Codification (ASC) 980 acknowledges that, for regulatory accounting purposes, regulators sometimes include the recovery of costs in periods other than the period in which costs would otherwise be charged to expense in GAAP financial statements if the company were not regulated.

That is, regulators sometimes find it necessary to allow regulated entities to establish a regulatory asset on their books for certain types of costs that would otherwise require expense treatment in the current period. The regulatory asset is established to allow a utility to recover costs from ratepayers over future periods. The regulatory asset accounts may or may not be included in rate base, depending on the circumstances.

ASC 980-340-25-1 states that an entity should defer all or part of an incurred cost that would otherwise be charged to expense if it is probable that the specific cost is subject to recovery in future revenues. The regulatory asset is initially measured as the amount of incurred cost.³²³ Recovery should be tied to a specific item. If a specific cost is determined not to meet criteria for deferral at the date incurred, it should be expensed; a regulatory asset may be established later when criteria for recognition are met.³²⁴

Future recovery is more difficult to prove in the absence of a rate order (which in most instances, initially, would be issued outside of a base rate case in its own proceeding). However, many times when regulatory assets are approved, the order states that allowing a regulatory asset for accounting purposes does not assure recovery of the item in rates.

Regulatory assets are typically amortized over future periods consistent with the period of recovery through rates.³²⁵ If at any time the criteria are no longer met or a regulatory asset becomes impaired, the remaining balance must be written off (i.e., charged to earnings).³²⁶ If a regulator subsequently allows recovery of costs that were previously disallowed (and expensed when incurred), a new asset is recorded.³²⁷

³²³ Utilities and Power Companies, PricewaterhouseCoopers, LLC, 2016, pp. 17-10 and 17-11.

³²⁴ *Id.*

³²⁵ *Id.*

³²⁶ *Id.*

³²⁷ *Id.*, p. 17-10 and pp. 17-16 through 17-17.

Below are two definitions from ASC 980-10-20 that are relevant to this topic:

- Incurred cost:
 - Arises from cash paid out or an obligation to pay for an acquired asset or service.
 - A loss from any cause that has been sustained and has been or must be paid for.
- Allowable cost:
 - All costs for which recovery is allowed.
 - Can be actual or estimated.
 - Can possibly include interest cost and amounts provided for interest on shareholders' investments.

The above two terms, incurred cost and allowable cost, are not interchangeable.

Examples of potentially allowable costs (regulatory assets aside) that are not incurred are:³²⁸

- A component for earnings on rate base (except as specifically allowed for allowance for funds used during construction).
- Provision for recovery of similar costs to be incurred in the future.
- Compensation for opportunity cost (such as margin on lost revenues).

Allowable costs that are not specifically incurred do not meet the definition of incurred costs, because they do not result from a past event, transaction, or loss that will require payment in cash. The distinction between these two types of costs is important, because only incurred costs qualify for capitalization as a regulatory asset (again, still not necessarily approved for inclusion in rate base) under ASC 980-340-25-1.

k) Regulatory Liabilities

ASC 980 also discusses regulatory liabilities. Actions by regulators may result in a liability by requiring a regulated entity to refund amounts to customers in the future or reduce future rates. Such action is accounted for as a regulatory liability. Regulators may allow costs in current rates to recover expected future costs and require future reductions in rates if costs are not incurred. Until costs are incurred, revenues collected are recorded as a liability and not recognized. Three general examples are refunds of amounts previously collected from ratepayers, current collections for future expected costs, and refunds of gains.³²⁹ These are not

³²⁸ *Id.*, 2016, pp. 17-10.

³²⁹ *Id.*, 2016, pp. 17-28.

necessarily reflected in rate base for ratemaking purposes, and items recorded in compliance with GAAP are not to be considered the result of regulators' action.

4. Rate of Return (ROR)

The fair rate of return is the compensation to investors expressed as a percentage and applied to a rate base stated in dollars as a component of the overall revenue requirement. The parameters of the concept of fair return have been defined by the judiciary in interpreting the confiscation clause of the U.S. Constitution (5th Amendment).

The allowed rate of return should be “reasonably sufficient” to:

- (1) Assure confidence in the financial soundness of the utility;
- (2) Maintain and support the utility's credit under efficient and economical management;
- (3) Enable the company to attract the capital necessary to provide service; and
- (4) Maintain the integrity of existing capital.³³⁰

The proper rate of return is dependent upon the risk of investment represented by the utility.

Certainly, a utility with monopoly status and a relatively stable revenue base represents a lesser risk than, for example, a speculative genetic engineering firm. The allowed rate of return should reflect this lower risk. Utility securities have historically been considered “blue chip” (i.e., lower risk) and a safe, dividend-yielding investment.

The overall rate of return allowed the utility is a function of three basic determinations:

- Capital Structure
- Cost of Debt Capital
- Cost of Equity Capital

These are discussed below.

But first, some discussion of “proxy groups” is important. A proxy (or barometer) group is a collection of similar risk companies that acts as a benchmark for determining the subject utility's rate of return and a check on capital structure. The criteria used to select the proxy companies are important—the proxy group needs to contain companies of similar risk in the

³³⁰ *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

industry but also needs to contain enough companies that one company cannot assert undue influence over the group.

The following criteria are often used to ensure that the group resembles the risks of the subject company's industry:

- (1) 50 percent or more of the company's revenues (or assets) must be generated from (or dedicated to) the utility's industry (water, natural gas, electric);
- (2) The company's stock must be publicly traded;
- (3) Investment information for the company must be available from more than one source; and
- (4) The company must not be currently involved in an announced merger or targeted in an acquisition.

Applying these criteria is not easy. The electric industry is a good example. Location of service territory in Value Line's (a major financial publication) eastern region has been used in the past to ensure that geographical risks (such as weather) are similar. On the other hand, due to consolidation in the industry and acquisitions made outside of the electric industry, a declining number of companies in the Value Line eastern group fit the four criteria. However, Pennsylvania electric utilities operate in a deregulated market and do not face the risks associated with generation assets (e.g., failure to clear the PJM market). The other states in the eastern region remain vertically integrated (no shopping exists, and the electric utility is responsible for both distribution and the supply of electricity). These are the type of considerations that affect the selection of the barometer companies.

a) Capital Structure

There are a variety of ways of raising capital in the market, but for utility purposes, they are primarily the sale of debt (bonds) and equity (ownership stock).³³¹ Preferred stock, a financial hybrid, is also used. There are countervailing benefits and detriments of both.

Generally, debt securities are less expensive than equity capital, because bonds have less risk exposure. Bonds are contractual agreements that provide for the payment of interest to the

³³¹ Short-term debt is included for gas companies when used to finance gas storage.

bond holder at fixed rates over an established term. The bondholder is repaid the original investment in full at the end of the contract.

In contrast, the equity holder has no assurance of dividends or repayment of the original investment. The stockholder stands at the end of the payment line after employees, vendors, and bondholders. Further, while the equity holder may be paid more for the stock than was originally paid (where the stock's price rises above the purchase price), he or she may also be paid less (the stock's price may fall below the purchase price for several reasons: overall market collapse, increased risk in the industry, or mismanagement of the company).

Equity provides a company with operating flexibility. Debt, with its fixed contractual payments, is an inflexible financing device. Although the lower cost rate of debt makes it an attractive financing option, the cash flow obligations that come with repayment create financial risk in the capital structure. Equity, with its lack of firm obligations, comes with no financial risk to the utility but has a higher cost rate, which is paid by utility customers. A balance must be found between the financial risk of debt obligations and the higher cost rate of equity.

In theory, there is an optimal ratio (or range) between the various combinations of financing available, which represents sound capitalization. The range of capital structures that is considered to be acceptable is found by observing the capital structure ratios of the proxy group. The most common capital structure for the utility industry is 50 percent debt and 50 percent equity.³³² The large ratio of debt relative to unrelated, riskier ventures, which may be largely equity-financed, is a measure of the stability of the utility industry. Where a utility employs an unreasonable capitalization (e.g., 100% equity), it is the policy of the PUC to impose a hypothetical capital structure based on the proxy group average to keep capital costs and allowed rate of return at a reasonable level.

b) Cost of Fixed Rate Capital

The cost of bonds and preferred stock is a simple mathematical calculation and mostly historical (unless a new issuance is projected to occur in the FPFTY). The cost of existing fixed rate capital is a known contractual rate that may be determined by averaging the various outstanding issuances of debt and preferred stock.

³³² Some industries may have slightly more equity; water, for example, may have as much as 300 more basis points in common stock.

An overlapping issue is the proper treatment of gain on reacquired debt. Debt is issued for a period of years, usually thirty, at which time the face value (i.e., original investment) is repaid by the utility. If debt is repurchased by the utility (either due to a mandatory redemption or at the utility's election) at a price below the original investment value, the PUC adjusts the debt (interest) rate of the company downward to reflect these gains on reacquired debt.

c) Cost of Equity Capital³³³

Determination of the proper return on equity capital is significantly more difficult. The equity cost rate is not fixed and is subject to fluctuation because of changing national economic and financial conditions, the market's current view of the sector, and the condition of the utility itself.

The U.S. Supreme Court, in its 1944 *Hope* decision³³⁴ held that "...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital...."

Regulators have always struggled with the best and most accurate method to use in applying the *Hope* criteria. There are two main conceptual approaches to determine a proper rate of return on common equity: "cost" and "the return necessary to attract capital." It must be stressed, however, that no single one can be considered the only correct method and that a proper return on equity can only be determined by the exercise of regulatory judgment that takes all evidence into consideration.

Discounted Cash Flow (DCF). The DCF is a well-established and commonly-used method that values a security as the discounted present value of expected cash flows. The DCF approach is based on the principle that the price an investor is willing to pay for a share of stock represents the present value of expected future cash flows from both dividend yields and the eventual sale of the stock. This future cash flow is discounted at the individual investor's required rate of return or, in other words, at his "opportunity cost" of foregoing alternative uses

³³³ For additional discussion of cost of capital methods and issues, see *The Cost of Capital - A Practitioner's Guide*, Parcell, D. C., Society of Utility and Regulatory Financial Analysts (2010); *The Cost of Capital, Intermediate Theory*, Armitage, S. Cambridge, UK: Cambridge University Press (2005); *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, Kolbe, Read and Hall, The MIT Press (2005); and *New Regulatory Finance*, Morin, R. A., Public Utilities Reports, Inc. (2006).

³³⁴ *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

for his funds. The actual stock price observed in the market is an average of the different levels of returns required by individual investors at their personal discount rates.

Although the theory behind the DCF has existed significantly longer, the DCF concept was first formally presented in Irving Fisher's *The Rate of Interest* published in 1907 and *The Theory of Interest* published in 1930 and was expanded by John B. Williams in his 1938 book *The Theory of Investment Value*. The most widely used form of the DCF was published by Professors Myron J. Gordon and Eli Shapiro in their 1956 analysis titled *Capital Equipment Analysis: The Required Rate of Profit*. Assuming that dividends will grow at a constant rate, the Gordon growth model can be simplified to the following:

$$K = \frac{D}{P} + g$$

Where:

K= current "cost" of common stock equity

D = dividends per share

P = market price per share

g = estimated growth rate

As stated, "K" is the rate of earnings that the investor is seeking. This is the investor's earnings objective in pricing the stock (P), in view of the dividend and growth factors he or she perceives. The dividends used (D) are either at the current rate or the rate anticipated for the coming year (experts differ on which is applicable). The stock price is at a recent time — an average over recent days, weeks or months (again dependent upon the views of the one making the calculation). The growth factor (g) expresses the growth of the price of the stock and dividends (or dividend yield) expected by investors.

While the D and P values require limited judgment (since they are essentially based on known data), the g value is more subjective. It is usually based on forecasts of earnings per share, dividends per share, and/or book value per share. Analysts' 5-year forecasts of growth rates are publicly available from online sources or through investor services such as Value Line, Yahoo!, Morningstar, Reuters, and Zacks.

A simple illustration of the application of this formula is as follows:

Assume that the stock of a utility is currently paying an annual dividend of \$2 per share and has a present market price of \$50. The average anticipated growth rate

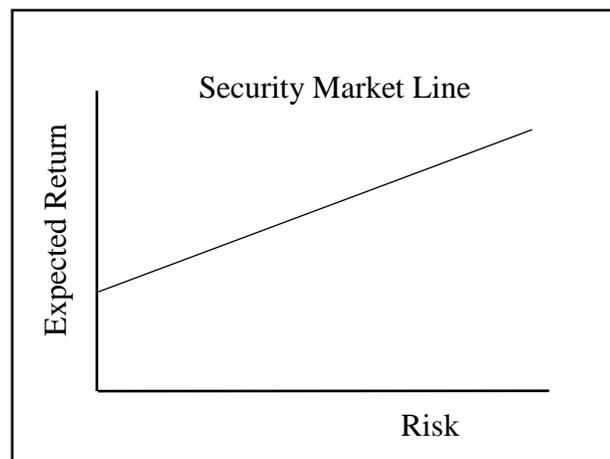
for both dividends and market value is calculated to be 6% annually. With these data, the current cost of common equity capital is computed to be 10%:

$$\begin{aligned} k &= \quad \$2 / \$50 \quad + 6\% \\ k &= \quad 4\% \quad + 6\% \\ k &= \quad 10\% \end{aligned}$$

The major advantages of the DCF approach include the ready availability of most of the required data and the simplicity of the actual calculations. More importantly, the DCF concept is forward-looking, and the use of company stock prices, dividends, and growth rates makes the DCF the most company-specific model.

On the other hand, critics of the DCF claim that the model does not follow the market or interest rates and therefore does not represent current market conditions. In addition, there is skepticism that analysts' shorter-term growth rate forecasts can be used in a more long-term model such as the DCF.

Capital Asset Pricing Model (CAPM). The CAPM is designed to measure the market rate of return and adjust it to match the relative investment risk of a security. The relationship between the expected return of a security and its investment risk is graphically represented by the Security Market Line, which demonstrates the idea that a security with less risk is expected to receive a lower return.



The CAPM describes the relationship between a security's investment risk and its market rate of return through the risk-free rate in addition to a market risk premium comprised of the difference between the risk-free rate and the return on the market adjusted for company-specific volatility. The formula of the CAPM is:

$$K = R_f + \beta (R_m - R_f)$$

Where:

K = the company's cost of equity capital

R_f = the risk-free rate

β = beta

R_m = the expected return on the market as a whole

The risk-free rate (R_f) reflects the return that can be earned without accepting any risk. Although there is no asset that is free of risk, in the CAPM, U.S. Treasury securities are usually considered a reasonable measure, as they are as close to default-free as possible. The choice of which maturity level to choose is more open to interpretation. At the shortest measure, the treasury bill with a one-to 12-month maturity is the most theoretically risk-free, as it carries very little inflation risk, but it is also the most volatile. Treasury notes that have a two- to 10-year maturity will be a better match to the term that the utility's rates are likely to be in effect, and while notes carry less inflation risk than a bond, they are still subject to some volatility due to changes in the market. Long-term treasury bonds of more than 10 years in maturity are the most stable of the treasury securities but are not risk-free, as they have substantial maturity risk associated with market risk and the risk of unexpected inflation.

Beta (β) gauges the tendency of a security's return to move in parallel with the overall market's return (e.g., the return on the Standard & Poor's 500). Beta is a measure of a security's volatility relative to the market's volatility. A stock with a beta of 1.0 tends to rise and fall by the same percentage as the market. Stocks with a beta greater than 1.0 tend to rise and fall by a greater percentage than the market and therefore have a higher level of market-related risk and are very sensitive to market changes. Similarly, a stock with a beta less than 1.0 has a low level of market-related risk and is less sensitive to market swings. Beta is a historical measure of the volatility of a stock and is determined through a linear regression analysis that measures the past performance of the stock in comparison to the market and adjusts for the tendency of a security to move towards a beta of 1.0. Betas are published by Value Line Investment Service and Bloomberg Professional Services. Since utilities are relatively low-risk investments, their betas typically average approximately 0.70.

R_m is the expected return on the market as a whole and is a more difficult factor to estimate. A historical approach can be used and assumes that investors expect returns in the

future to be about the same as returns in the past. The average annual return on the market as a whole (or an index such as the S&P 500) from 1953 to 2016 averages 12.06%. A prospective market return can also be used that better matches the time period in which the rates being set will be in effect, but the estimation of where the market will be in the future is difficult to accurately measure. The DCF method can be used to estimate the future return on the market by using the dividend yield and growth rates of the S&P 500 or the Value Line universe of stocks.

The following is the historical CAPM approach using data from 1953 through 2016:

$$\begin{array}{rclclclcl}
 K & = & R_f & + & B & (R_m & - & R_f) \\
 K & = & 5.25\% & + & 0.7 & (10.6\% & - & 5.25\%) \\
 K & = & 5.25\% & + & 0.7 & \times & 5.35\% \\
 K & = & 5.25\% & + & & 3.75\% \\
 K & = & 9.00\% & & & & &
 \end{array}$$

The arguments in support of the CAPM include its basis in the concept of risk and return, its company-specific nature via the use of beta, and its widespread use in the investment community. However, critics of the CAPM question the accuracy of a method that attempts to measure the cost of equity by observing the difference between a risk-free security and the market instead of directly measuring the cost of equity. In addition, there is doubt that beta is a valid measure of the risk-return relationship. One of the most famous debates on this topic began with a study by Eugene F. Fama and Kenneth R. French,³³⁵ which found that there was virtually no relationship in the beta risk and return relationship and that other factors (size, market-to-book ratios, etc.) did a better job of explaining the variations in returns.

Risk Premium. This is a simplified CAPM approach. The risk premium approach is based on the idea that stocks are riskier than debt, and so, investors require a higher return on stocks. The general method is to determine the spread between the cost of debt and the cost of equity and add that spread to the current debt yield to determine the cost of equity.

³³⁵ *The Cross-Section of Expected Stock Returns*, Fama, E. F., & French, K. R., *The Journal of Finance*, Vol. XLVII, No. 2 (June 1992).

The formula for the risk premium approach is:

$$K = C_d + P_r$$

Where:

K = cost of equity capital

C_d = cost of debt

P_r = equity risk premium

Note that this approach results in an average market cost of equity capital without regard to the utility under consideration in a specific rate case. One of the basic and most disputed assumptions of the risk premium method is that the equity risk premium is constant over time.

Comparable Earnings. This method seeks to determine what the capital that investors have placed in a utility could earn if it were invested in other enterprises of similar risk and uncertainty, either in the utility industry or in other industries, since the investor is entitled to a return at least equal to what he could get elsewhere. Although the Comparable Earnings method is not grounded in economic theory like the DCF and CAPM, it is argued that it is easy to calculate, and since it does not involve the determination of growth rates or expected returns on the market, it is claimed to be less subjective.

The main difficulties affecting this method are: (1) the choice of which companies are of comparable risk is subjective; (2) if other regulated utilities are used for comparison, the CE method produces a high degree of “circularity” (i.e., if every regulatory agency followed the policy of allowing the same return as every other regulator, the process would become circular); and (3) it is questioned whether historic accounting values are of use in a future test year.

Forming a group of comparable risk companies can include the following criteria:

1. Comparing ratios of market price per share to book value per share to a utility proxy group.
2. Comparing beta to a utility proxy group.
3. Comparing Value Line ranks (i.e., timeliness, safety, and technical) to a utility proxy group.

Circularity cannot be avoided when comparison is being made with other regulated companies. The answer clearly is to use as broad a comparison group as possible. Some feel that it should include not only companies in the same regulated industry but those in other regulated industries and in non-regulated industries as well, since earnings of the latter can at least serve to

mark the upper limits of reasonableness for public utility earnings. Others, however, urge care in comparing non-regulated industries with utilities, because investors seek security from utility common stocks, rather than growth potential. Regulators have hesitated to rely on the comparable earnings approach because of the difficulty of coming up with an acceptable sample of comparable companies.

Adjustments to the Cost of Equity

Market-to-Book Adjustment. Some claim that the difference between the market value and the book value of a firm cause the overall rate of return to be underestimated when a market-based cost of equity is applied to a book value capital structure. Although in the past utilities' market value was less than their book value, the market value in all utility industries currently is significantly above book value. Proponents of this adjustment argue that the difference in market and book values cause the market-based DCF and CAPM to understate the cost of equity when applied to a book value capital structure. Critics of the adjustment argue that the market is efficient and stock prices reflect all relevant and ascertainable information, including differences between market and book values.

Size Adjustment. Companies of smaller size are considered to be of greater risk and therefore have a greater cost of capital. Empirical studies have demonstrated that, in the market, the size of a company is an indicator of risk and, therefore, equity returns; as the size of a company decreases, equity returns tend to increase. Proponents of this adjustment claim that size is also an indicator of risk in utility companies and that the cost of equity estimated by a proxy group of large companies does not accurately reflect the risk of a smaller company for which the cost of equity is being estimated. Critics of the adjustment point out that the only empirical evidence supporting a size adjustment is based on studies that are not utility-specific. A study of only utility companies found that industrial stocks and utility stocks do not share the same characteristics and that there is no need to make a size adjustment in utility rate regulation.³³⁶

ROE Performance Premium. The Commission may also add a premium to the model-indicated return as an incentive or reward for actions taken that are favored by the Commonwealth's policy goals. Code § 523 (enacted 1986) contains the directive that the

³³⁶ Wong, A. (1993). Utility Stocks and the Size Effect: An Empirical Analysis. *Journal of the Midwest Finance Association*, 95-101.

Commission consider “in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates....” The listed items that trigger this provision include management effectiveness and operating efficiency, encouragement of conservation, and load management. The Commission has also made a rate of return premium available for water acquisitions.³³⁷ The Commission has raised the allowed ROE in several instances, citing management performance,³³⁸ and rejected it in others.³³⁹

d) Overall Cost of Capital

By combining the costs of debt and equity with the capital structure, the overall cost of capital to the utility can be determined. For example, consider Typical Utility, which has a 50% debt/50% equity capital structure and a 5% cost of embedded debt. The PUC has determined the cost of equity to be 10.00%. Thus, the overall cost of capital allowed to Typical Utility by the Commission would be 7.50%, calculated as follows:

Type of Capital	Ratio	Cost Rate	Weighted Cost
Long-term Debt	50.00%	5.00%	2.50%
Common Equity	50.00%	10.00%	5.00%
Total	100.00%		7.25%

This 7.25 percent overall cost of capital is multiplied against Typical Utility’s rate base to determine the revenue requirement share necessary for the shareholders’ return on investment. This amount must then be “grossed up” for income taxes. If the total revenue requirement (RR)

³³⁷ Regs § 69.711(b)(1).

³³⁸ See, for example, *Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, Opinion and Order (Dec. 5, 2012)(“ ... we shall grant PPL’s Exception and adopt its twelve basis point management effectiveness adjustment to our prior return on equity recommendation in recognition of its exemplary managerial performance.”) and *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, Opinion and Order (July 31, 2008) (“Accordingly, we shall grant Aqua’s Exception, in part, and add 22 basis points to Aqua’s DCF result in recognition of its exemplary managerial performance.”).

³³⁹ See, for example, *Pennsylvania Public Utility Commission v. West Penn Power*, Docket No. R-922378, Opinion and Order (March 19, 1995) (“Although West Penn is a relatively well managed operation with comparatively low prices, based upon the evidence and position set forth by WPPII especially, but also those of the other parties, West Penn has not proven that it deserves a 25 basis point adjustment to its cost of common equity.”).

(return and allowable expenses) needed for the prospective period that the rates are to be in effect is greater than the current level of revenues, the difference is the amount of the rate increase granted.

H. Rate Structure and Design

1. Overall

Once the revenue requirement of the utility has been determined, the next (and final step) is the translation of the overall increase into tariffs. Once the size of the “pie” is determined under the RR formula, it is then parsed into “slices” —groupings of customers with similar usage patterns. There are two steps: the allocation of revenue responsibility between rate classes and the distribution of that portion into individual rate elements (e.g., \$ per kW, \$ per kWh, \$ per month).

Rate design is more of an art than a science, and considerable judgment is involved. Beyond the basic concern of allowing the utility the opportunity to earn the allowed revenue increase, there are a variety of other factors to be considered: the cost of service by rate class, value of service, gradualism (meaning rates should not be raised too abruptly), policy objectives (e.g., conservation), and social welfare considerations.

Numerous authors and organizations³⁴⁰ have laid out goals and principles of rate design. James Bonbright’s *Principles of Public Utility Rates*³⁴¹ lists the following “attributes” of a desirable rate structure:

- (1) Effectiveness in yielding total revenue requirements under the fair-return standard.
- (2) Revenue stability and predictability from year to year.
- (3) Stability and predictability of the rates themselves with a minimum of unexpected changes seriously adverse to existing customers and a sense of historical continuity. (“The best tax is an old tax.”)
- (4) Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

³⁴⁰ See, for example, NARUC *Electric Cost Allocation Manual* (January 1992) at: <http://pubs.naruc.org/pub/53A20BE2-2354-D714-5109-3999CB7043CE>.

³⁴¹ *Principles of Public Utility Rates*, James C. Bonbright (Public Utilities Reports, 1988). First published in 1961, Bonbright’s treatise is well thought out, readable, and still timely. It is recommended reading for anyone interested in rate setting.

- a. In the control of the total amounts of service supplied by the company; and
 - b. In the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, higher quality service versus lower quality service).
- (5) Reflection of all present and future private and social costs and benefits occasioned by the service's provision.
 - (6) Fairness of the specific rates in the apportionment of total costs of service among the different consumers to avoid arbitrariness and capriciousness.
 - (7) Avoidance of undue discrimination in rate relationships so as to be compensatory (i.e., subsidy-free with no inter-customer burdens).
 - (8) Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.
 - (9) The related "practical attributes of simplicity, understandability, public acceptability, and feasibility of application."
 - (10) Freedom from controversies about proper interpretation.

Bonbright distills these down to three primary criteria of rate design from which his others flow:

Criterion 1 - Capital attraction. The revenue-requirement objective;

Criterion 2 - Consumer Rationing. Rates designed to discourage the wasteful use of services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received; and

Criterion 3 - Fairness to Ratepayers. Fair cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* among the beneficiaries of the service.

The Commonwealth Court has previously affirmed the following Commission sentiment discussing the scope of the considerations involved:

There is no requirement that rates for different classes of service must be either uniform or equal or that they must be equally profitable. Differences in rates between classes of customers based on such criteria as the quantity of electricity used, the nature of the use, the time of the use, the pattern of the use, or based on differences of conditions of service, or cost of service are not only permissible but often are desirable and even necessary to achieve reasonable efficiency and economy of operation. Rate structure, which is an essential, integral component of rate-making, is not merely a mathematical exercise applying theoretical principles. Rate structure must be based on the hard-economic facts of life and a complete and thorough knowledge and understanding of all the facts and circumstances which affect rates and services; and the rates must be designed to furnish the most efficient and satisfactory service at the lowest reasonable price

for the greatest number of customers, i.e., the public generally. While cost to serve is important, other relevant factors may also be considered.³⁴²

Having said this, however, Pennsylvania courts have tended to require a valid explanation for any significant deviation from the class cost of service study results. The court has stated that “in order for a rate differential to survive a challenge brought under Section 1304 of the Public Utility Code [bar against rate discrimination], the utility must show that the differential [different rates among the classes] can be justified by the difference in costs required to deliver service to each class. The rate cannot be illegally high for one class and illegally low for another.”³⁴³

In a 2006 decision, the Commonwealth Court held that a substantial difference in the rate of return by class³⁴⁴ in an electric company cost study could not stand:

However, while permitted, gradualism is but one of many factors to be considered and weighed by the Commission in determining rate designs, and principles of gradualism cannot be allowed to trump all other valid ratemaking concerns and do not justify allowing one class of customers to subsidize the cost of service for another class of customers over an extended period of time.

...in effect, the Commission has determined that the principle of gradualism trumps all other ratemaking concerns—especially the polestar—cost of providing service. Not only did the Commission allow gradualism to trump all other factors without providing a sufficient explanation, the total bill method is not in accord with the Competition Act. Section 2804(3) of the Competition Act mandates rates for services as unbundled charges for transmission, distribution and generation and requires that rates and rate structures be set for each service primarily on a cost of service study.³⁴⁵

³⁴² *Philadelphia Suburban Transportation Company v. Pennsylvania Public Utility Commission*, 3 Pa Cmwlth. 184, 281 A.2d 179, 186 (1971) (quoting with approval from a Commission opinion).

³⁴³ *Philadelphia Suburban Water Company v. Pennsylvania Public Utility Commission*, 808 A.2d 1044, 1060 (Pa Cmwlth. 2002).

³⁴⁴ PPL’s cost of service study on appeal indicated that under present rates, the commercial GS-1 (small business) customer class paying a class rate of return of 9.28 percent, whereas the residential service class showed only a 1.60 percent with a system average return of 3.9 percent proposal. Under proposed rates, the GS-1 rate of return would be 16.17 percent as compared to a rate return of 5.29 percent for the RS customers, with an overall company rate of return of 8.8 percent. The Commission concluded that these ROR differentials were not unreasonable and were justified based on the principle of gradualism and mitigation of rate shock.

³⁴⁵ *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa Cmwlth. 2006) (*Lloyd*). Code § 2804(3) provides that “the commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution.”

It is evident that rate structure has many competing interests to serve, but as Judge Pelligrini, writing for the majority, said in *Lloyd*, for class revenue allocation purposes, cost of service is the “polestar.”

Given that cost of service is the “polestar,” it follows that utilities providing more than one different type of utility service cannot shift costs from one operation to the other. For example, a utility that provides both gas and electric service cannot require its gas customers to pay for plant serving electric customers. An exception to this fundamental rule is for utilities that provide both water and wastewater service. Section 1311(c) of the Code permits utilities that provide water and wastewater service to combine the revenue requirements by allocating a portion of the wastewater revenue requirement to the water customer base if doing so is in the public interest. For example, in Pennsylvania American Water Company’s (PAWC) 2017 base rate proceeding, Docket No. R-2017-2595883, PAWC proposed to allocate \$13,805,200 of its wastewater revenue requirement to water customers, which would increase the average residential water bill by approximately \$1.27 per month. Section 1311(c) does not specify how the Commission should determine rates, nor does it dictate the amount of revenue that should be allocated or shifted, leaving the Commission wide latitude in applying this provision.

Any subsidization of wastewater operations by water operations should be reviewed on a case-by-case basis to balance the interest of the utility and its water and wastewater customers. To make this determination, the filing must be presented such that revenues, expenses, rate base, taxes, and return for the various water and wastewater operations are segregated and presented in separate cost of service studies in order for the revenue requirement and any wastewater revenue shortfall to be identified. The utility must provide support for shifting the wastewater revenue shortfall to water customers and must show that increasing the water revenue requirement (and corresponding rates paid by water customers) above what the water operations would normally receive is reasonable and in the public interest.

2. Cost of Service and Customer Classes

Class cost of service³⁴⁶ is determined by the way in which the service is used. Many factors, including consumption patterns, climate conditions, density of population, design, and

³⁴⁶ It is confusing that the overall revenue requirement for the utility is sometimes also referred to as the “cost of service”, but the context usually will give you a clue as to which stage of the rate case is being referred to.

utilization of equipment, affect usage and demand characteristics. Recall from the previous discussion of utility operating characteristics that the cost of providing service varies from hour to hour, day to day, and month to month, and these usage characteristics create costs. Each individual customer imposes a different combination of costs on the system, and the cost to serve is unique to each. Ideally each customer should be on a separate tariff reflecting those costs, but such a solution is administratively infeasible.

Thus, customers with homogeneous characteristics are grouped together as a customer class, and tariffs are designed to recover the cost of serving the class. The basic classes are residential, commercial and industrial. These are often broken down into the customers' relative size within these categories. So, for example, the following classes of consumers might be carved out in this electric example:

- RS - Residential Service
- RTS(R) - Residential Service - Thermal Storage
- RTD(R) - Residential Service - Time of Day
- GS - General Service - Secondary Voltage
- LP1 - Large General Service – 69 KV or Less
- LP2 - Large General Service - 69 KV or Higher
- IS-1 - Interruptible Service
- IS-P - Interruptible Large General Service - 12 KV or Higher
- IS-T - Interruptible Large General Service - 69 KV or Higher
- SM - Mercury Vapor Street Lighting
- SHS - High Pressure Sodium Street Lighting
- SLE - Light Emitting Diode (LED) Street Lighting Service
- SE - Energy Only Street Lighting Service
- TS - Municipal Traffic Signal Lighting Service

Usage is different among the classes (i.e., residential uses less than commercial and industrial), but so, too, are demand characteristics. Residential customers tend to consume utility service during peak periods, thereby placing greater per unit cost on the system than industrial consumers who operate around the clock at a stable level of demand (i.e., a flatter load curve). In addition to being more base than peak load, industrials take power at higher voltages and, therefore distribution costs are less on both a kWh and KW basis. It is this relative cost causation that a cost of service study attempts to isolate.

Any proposed increase exceeding \$1 million must be accompanied by a cost of service study.³⁴⁷ In the study, every item of cost is assigned to the customer classes based upon engineering, operating, economic, and legal principles. There are three basic steps to a cost of service study:

- (1) Functionalize;
- (2) Classify; and
- (3) Allocate.

Functionalization identifies the costs attributable to the provision of service, excluding non-utility or other utility service items, and groups them according to the following functions (and their underlying sub-functions):

<u>Electric</u>	<u>Gas</u>	<u>Water</u>
Customer	Customer	Customer
	Production	Production
	Storage	Storage
		Treatment
	Transmission	
Distribution	Distribution	Distribution

Most cost items are already functionalized under the Uniform System of Accounts. Other shared costs (e.g., income taxes, cost of capital, administrative) must be allocated within these functions.³⁴⁸

The functionalized costs are then classified by the manner in which they are incurred:

- (1) Demand/Capacity Costs - These are the capital and operating expenses incurred to provide sufficient capacity to meet peak demand. These costs are not affected by the number of customers or annual usage, but rather are put in place to serve the peak; or

³⁴⁷ Regs. § 53.53.

³⁴⁸ For example, a general overhead count, such as income taxes, could be allocated among the classes based on the percentage of total rate base allocated to that class. If the class cost of service ended up allocating 25 percent of rate base to the residential class, so too would 25 percent of income taxes be allocated. Allocated revenues would be another basis.

- (2) Commodity/Energy Costs - Costs that vary in direct proportion to the volume of service consumed. These costs are not related either to capacity or customer costs; or
- (3) Customer Costs - The costs affected directly by the number of customers served, regardless of usage, are included in this category. They include the cost of meters, meter reading, billing, and some portion of the distribution system.

The decisions made at this step will tend to drive costs to one class more or less than another because of the unique class usage and demand characteristics of each class (e.g., residential winter gas peaking load vs. industrial base load).

Once costs are functionalized and classified, the final step is to assign and allocate the costs among the various customer classes. Costs exclusively incurred on behalf of one customer or class of customers should be directly assigned to that customer or class. Class ratios must be developed to allocate the remaining costs.

For example, costs that have been classified as customer-related would be allocated as follows:

TYPICAL UTILITY Customer Allocation Factor		
Class	Number of Customers	Ratio to Total
Residential	75	0.75
Commercial	15	0.15
Industrial	<u>10</u>	<u>0.10</u>
Total	100	1.00

Therefore, 75 percent of all customer-classified costs, not directly assigned, would be allocated to the residential class.

A particularly controversial area of rate structure is the proper allocation of demand-related costs. There are two main methods and a hybrid:

Coincident peak is one method. This method assumes that the demand responsibility should be allocated among the classes based upon the company's peak demand. Peak demand is characteristic of engineering design considerations of each

utility. The company may use one day or a combination of peak periods to best reflect these operating characteristics. In all cases utilizing coincident peak, demand costs are allocated in proportion to the class' contribution to the peak demand.

Non-coincident peak is another, representing a sum of the particular class' individual peak demand, regardless of when it occurs or whether it coincides with the company peak.

The **average and excess method** recognizes both the average use and the peak use of capacity.

No matter which demand methodology is employed, the accuracy of the underlying load data must be reliable. Because demand metering is expensive, utilities do not measure demand for all customers, but rather conduct load research studies.³⁴⁹

For gas utilities, the allocation of the cost of mains, which comprise the largest component of rate base, can be a contentious issue. An allocation based 50% on a demand factor and 50% on a customer factor is often proposed. This method of allocating the costs of distribution mains is known as the "customer/demand" methodology and recognizes that mains are sized to meet peak load and installed to reach each customer. It tends to allocate more costs to the residential class with its relatively higher number of customers. However, the Commission has determined that mains serve a dual purpose: to send gas and to meet the peak demand of the customers. Therefore, the cost of mains should be allocated 50 percent based upon the demand of each class (using the average and excess method) and 50 percent based upon the volumetric throughput of each class (i.e., a combined demand/usage factor).³⁵⁰ Under this method, no

³⁴⁹ True for natural gas, but as described previously, the electric companies are mandated to deploy smart meters under Pennsylvania law and individual demand data will be available once installed.

³⁵⁰ *Pa PUC v. Philadelphia Gas Works*, Docket No. R-00061931, Order (Sept. 28, 2007) ("Reviewing the record, we find that the allocation of distribution mains investment costs should be done using both annual and peak demands."). PGW had proposed using a 25/75 allocation using customer and demand functions. See also, *Pennsylvania Public Utility Commission v. PPL Gas Utilities Corporation*, Docket No. R-00061398, Order (Feb. 8, 2007) where the Commission accepted an allocation method that classified the distribution mains costs as 40 percent commodity usage and 60 percent excess demand.

customer-based allocation factor is recognized, and the costs allocated to the residential class are lower.³⁵¹

3. Rate Design

a) Interclass Revenue Responsibility

The result of a cost of service study is rate of return by class, a measure of the profitability of the various classes, under both existing and proposed rates. A typical presentation, this one for existing rates using Typical Utility’s fully projected future test year, would be as follows:

Typical Utility Test Year Ending Dec. 31, 2019 Present Rates (\$ in thousands)				
	Total	Residential	Commercial	Industrial
Operating Revenue	\$2,000	\$930	\$510	\$560
Operating Expenses and Taxes	\$1,670	\$800	\$420	\$450
Operating Income	\$330	\$130	\$90	\$110
Rate Base	\$4,000	\$2,000	\$1,000	\$1,000
Rate of Return	8.25%	6.50%	9.00%	11.00%

This figure shows that, while the overall company return before the rate increase (present rates) was 8.25 percent, only a 6.5 percent return was received from the residential class, and the commercial and industrial returns were higher at 9 percent and 11 percent, respectively. Thus, if all costs have been functionalized, classified, and allocated properly, the commercial and industrial classes are subsidizing residential customers.

However, absent other considerations, customer classes should pay their cost of service without subsidization by other classes. While complete closure (i.e., equalizing customer class rates of return) may not be possible, Typical Utility concludes that some closure is appropriate

³⁵¹ Electric distribution plant is treated differently. Distribution plant can be allocated based on customer and demand functions. *PA PUC v. PPL Electric Utilities*, Docket No. R-2012-2290597, Opinion and Order (Dec. 28, 2012).

and thus assigns the rate increase to move toward unity in rates of return (i.e., unity equals the overall company return).

Therefore, if Typical Utility decides to begin closing the gap of disparate class returns, the presentation for proposed rates might appear as follows:

Typical Utility Test Year Ending December 31, 2019 Proposed Rates (\$ in thousands)				
	Total	Residential	Commercial	Industrial
Present Operating Revenue	\$2,000	\$930	\$510	\$560
Rate Increase	<u>\$180</u>	<u>\$150</u>	<u>\$20</u>	<u>\$10</u>
Proposed Operating Revenue	\$2,180	\$1,080	\$530	\$570
Operating Expenses and Taxes	<u>\$1,760</u>	<u>\$875</u>	<u>\$425</u>	<u>\$460</u>
Operating Income	\$420	\$205	\$105	\$110
Rate Base	\$4,000	\$2,000	\$1,000	\$1,000
Rate of Return	10.50%	10.25%	10.50%	11.00%
 PERCENT INCREASE	 9.0%	 16.1%	 3.9%	 1.8%

Thus, of Typical Utility's proposed \$180 million (9 percent) overall increase, \$150 million (83 percent) is proposed to be collected from the residential class for a class increase of 16.1 percent over existing rates. Commercial and industrial customers will receive an increase of \$20 million and \$10 million, or 3.9 percent and 1.8 percent, respectively.

Yet even with this substantial increase, the residential class would continue to pay less than the cost of service (expressed as a percentage of the overall company return or "unity"), and subsidization would still exist, as shown below:

Typical Utility Test Year Ending December 31, 2019 Present Rates (\$ in thousands)					
	Existing Rates		Proposed Increase	Proposed Rates	
	ROR	Relative		ROR	Relative
Residential	6.50%	0.788	\$150	10.25%	0.976
Commercial	9.00%	1.091	\$20	10.50%	1.000
Industrial	11.00%	1.333	\$10	11.00%	1.048
TOTAL	8.25%	1.000	\$180	10.50%	1.000

This shows that the commercial and industrial returns have gone from 1.091 and 1.333 times the overall return, respectively, to 1.000 and 1.048 times, respectively, a movement toward unity. Meanwhile the residential return has gone from 0.788 to 0.976 of unity.

While Typical could have designed rates to abolish subsidization altogether (i.e., all classes at 100 percent of unity), this would have required an increase greater than the 16.1 percent proposed for the residential class and a small increase for the other two classes. This is the ratemaking principle of gradualism, counseling a slower incremental movement toward actual cost of service and the avoidance of sudden, quick increases in rates.

b) Intraclass Rate Considerations

Once the proper allocation of the overall rate increase among the various classes has been addressed, the allocated increases must be translated into actual rates.

The first step is to review the functions of the costs that have been allocated to that class.

Customer Charge - As discussed above, one classification of costs is the customer-related category. The functions of meter reading, billing, mailing, and collecting must be performed regardless of the level of consumption. The local distribution line, the service drop, and the meter are installed and must be depreciated and earned upon, even if the customer is on vacation that month and uses no services. Under standard rate design, these costs, or the customer allocated share of these costs, are collected through a fixed customer charge, which is imposed separate from any usage charges. Even if no kWh, Mcf, or Mgals are consumed by the customer, the customer charge is billed.

This can be a controversial area of rate design, as companies propose to collect more revenues on a predictable, steady cash flow basis and consumer advocates oppose the upfront loading of rates. Typically, companies will categorize a significant number of costs as customer-related in order to capture more revenue in fixed costs. When a company's customer cost allocations are evaluated to eliminate costs that have traditionally been considered usage- or demand-related, the resultant customer-related costs are often lower than the company's claim.

Another variation is a minimum charge that combines the customer charge and a small amount of consumption.³⁵²

Usage charges collect the cost of assets and expenses that are related to commodity/energy costs—those that vary in direct proportion to the volume of service consumed—expressed as kWh, Mcf or Mgals.

Demand charges collect those costs incurred to provide sufficient capacity to meet peak demand. Such a charge, usually imposed on large customers with demand meters, is based upon the maximum demand imposed by a customer within a specified timeframe and is designed to recover the utility’s investment in existing capacity.

c) **Rate Tables**

The next step is to set up the rate table. The functionalization of costs into customer, commodity, and demand, as described above, is relevant but is not strictly followed. For residential customers, demand costs are typically recovered in the usage block, although some states are offering demand rate options to residential customers with the advent of smart meter capabilities.

Conceptually there are four basic rate designs:

- (1) **Declining block rate;**
- (2) **Inverted block rate;**
- (3) **Flat rate;** and
- (4) **Peak load pricing.**

A **declining block rate** (“the more you use, the less you pay per unit”) with a customer charge for an industrial served off a 2” line by The York Water Company (Tariff Supplement 117) is as follows:

Customer Charge	\$62.00 per month
Up to 5,000 Gallons Per Month	\$ 4.111 per Mgal
Next 45,000 Gallons Per Month	\$ 2.944 per Mgal

³⁵² This does not apply to electric rate design due to the unbundling of energy from customer-, distribution-, and transmission-related costs.

Next 1,950,000 Gallons Per Month	\$ 2.588 per Mgal
Over 2,000,000 Gallons Per Month	\$ 2.228 per Mgal

A declining block rate for large industrial transportation service (customer-supplied gas) with a demand and customer charge appears in UGI's current tariff (Tariff Supplement No. 6, Rate LFD) as follows:

Customer Charge	\$700.00 per month
Demand Charge	\$5.45/Mcf of Customer's elected DFR (Daily Firm Requirement)
Distribution Charge	First 1,000 Mcf @ \$1.5470/Mcf Over 1,000 Mcf @ \$1.0465/Mcf

The various riders, including STAS and DSIC, are then added on top of these base rates.

The prominent feature of this design is the decreasing rates associated with increasing consumption. Declining block rates are cost-based because of economies of scale (i.e., decreasing nature of the fixed charges). They are criticized as not encouraging conservation. Low-income advocates tend to support lower initial blocks for residential service on the grounds that low-income households consume less.

Inverted or inclining block rates ("the more you use, the more you pay per unit") are the converse of declining block (i.e., higher charges for greater usage). It is believed that this rate design incentivizes lower consumption per customer and promotes home weatherization and appliance efficiency. It is not particularly cost-based, since costs per unit generally decline with greater volume.

Under **flat rates**, the price of each unit is the same regardless of usage levels. This is not a cost-based method of rate setting. Its principal attraction is simplicity. So, for example, Columbia Gas' current (Tariff Supplement No. 264) rate design for residential sales service is:

Customer Charge	\$ 16.75 per month
Usage Charge	\$ 1.08818 per therm consumed

The Residential Distribution Service (Rate RDS), where the customer chooses the supplier, is of a similar design for Columbia customers:

Customer Charge	\$ 16.75 per month
Usage Charge	\$ 0.73852 per therm transported

Flat rates are used for pricing of street lighting where the usage is known in advance (dusk to dawn) and pricing schedules set based upon the efficiency of the bulbs used, with separate rate schedules for mercury vapor, high pressure sodium, and LED lights.

It is not unusual for water and waste water companies, particularly municipal-owned, to provide service under a periodic (e.g., quarterly) flat rate (e.g., \$65 per quarter) with no usage charge. The Commission's policy is to require the installation of meters³⁵³ and set usage rates to encourage conservation. Fire hydrant service, where no meter is practical, is exempted, and the rate is a flat per month charge.

Peak load pricing has gained increased acceptance, since it sends economic signals to the customer that reflect the cost impacts of peak usage. There are numerous forms of this type of rate: time of use, load factor, seasonal, etc. The advantage of such a rate is that it encourages more complete use of existing utility plant and load management. Under peak load pricing, a higher charge for service is levied during peak periods of use. As discussed in the operating characteristics section, energy utility use has daily, weekly, and annual peaks. By charging a lower rate for off-peak usage and a higher rate for peak usage, customers are induced to shift their consumption patterns to off-peak usage, thus leveling the company's load curve and decreasing overall costs.

The **Straight Fixed Variable (SFV)** method is another theory of rate design. As discussed previously, almost all costs for building and maintaining a natural gas delivery system, an electric grid, or a water service are fixed and do not vary with user consumption. Yet these fixed costs are frequently recovered in the commodity blocks of the tariffed rate. SFV designed rates rigorously (hence, the term straight) segregate all fixed costs associated with service (including return on equity, taxes, and depreciation³⁵⁴) and place them in the fixed charge imposed, regardless of how much gas, electric, or water is used.³⁵⁵

³⁵³ Regs. § 65.7 ("except fire protection customers").

³⁵⁴ A variation, modified fixed variable rate design, recovers the fixed costs of return on equity and income taxes in the commodity charge.

³⁵⁵ In the Joint Petition for Settlement of Columbia's 2012 base rate proceeding at Docket No. R-2012-2321748, the parties agreed to a \$16.75 monthly residential customer charge. Under the straight fixed variable approach, the monthly customer charge would have increased to a much higher level (\$45.49 per month was proposed by the company). No usage would have been included.

SFV rate design is used by the FERC for pipeline transportation rate setting but is not widely used for retail rate design. The primary benefit is utility revenue stability, at least in the short term. Criticism includes a lack of affordability, discrimination against low-volume users, and disincentives to consumer conservation. Moreover, it is argued, the notion of fixed costs is shortsighted, because in the long run all factors of production are variable. Meters, poles, pipelines, etc. are ultimately replaced, and the objective is to shape behavior in the long run.

d) Electric Retail Rate Design Considerations

As noted previously, the Choice Act of 1996 requires that the EDCs' electric rates be unbundled into their functions (energy, distribution, and transmission), with the energy component (the electrons) being available for purchase at the customer's choice in an open, competitive supply market. This has dramatically changed electric rate structure, moving it away from a fully integrated declining block, for example, into flat-rated components. So, for example, Residential Service (Rate RS) under PPL's current tariff (Tariff Supplement No. 194):

Customer Charge	\$16.67 per month
Distribution Charge	4.453¢ per kWh
Transmission Service Charge	0.01662¢ per kWh

The energy can then be selected from an EGS or PPL, whose current PTC is:

Energy (usage) Charge	0.084930¢ per kWh
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To this the various surcharges, such as the DSIC and universal service riders, apply.

This type of rate design is "static" pricing. It is metered monthly, with prices changing infrequently for transmission and distribution (in an EDC base rate case) and energy (under your EGS contract terms or the PTC quarterly).

Smart meter technology is in the process of widespread deployment in Pennsylvania and, once accomplished, will significantly change electric rate design and customer behavior.³⁵⁶ A smart electric meter is an electronic device that tracks, and records customers' electricity use through a two-way radio frequency communication. This replacement to the old analog meters measures electric usage more often than conventional meters and sends that information more

³⁵⁶ As noted previously in the operating section of this handbook, Pennsylvania's Act 129 of 2008 set a goal of universal smart meter deployment by Duquesne Light, Met-Ed, Penn Power, PECO Energy, Pennelec, PPL Electric, and West Penn Power by 2023.

quickly to the customer and the EDC, as well as a participating EGS. These service providers (and customers) can gauge peak usage accurately by controlling equipment (with the customer's permission); shed load at peak times; and shift usage to different times of the day when electricity costs less, thereby avoiding peak costs and lowering the customer's bill.

Billing customers on a more immediate basis than the traditional monthly measurement offers an opportunity to design rates on a real-time basis using your home's actual usage and the price of wholesale power at that same time (called "dynamic pricing"). Combined with the features of a smart home, where appliances can be turned on and off remotely by the customer or the energy supplier (EDC or EGS), the customer could experience considerable savings by purchasing energy from less costly sources, and the utility can avoid new construction projects.

4. Compensation for Distributed Electric Generation

There are many sources of customer-generated electricity (also called "distributed energy"). Rooftop solar is an area of strong growth, driven in large measure by diminishing manufacturing costs and favorable installation terms offered by the industry. Solar City,³⁵⁷ for example, a major industry participant, offers financing by loan, lease, and purchased power agreement³⁵⁸ with low or no upfront costs. The electric distribution industry and regulators are adapting to accommodate this trend.

As of May 2017, there were 16,130 customer-generators,³⁵⁹ with a total nameplate capacity of 292,410 kWh interconnected to Pennsylvania EDC distribution systems.³⁶⁰ This has been an area of explosive growth. There were only 10,648 such sources in the prior year. Between 2015 and 2017, the number of interconnection requests by Level I generators³⁶¹ grew annually from 614 to 8,046.

³⁵⁷ <http://www.solarcity.com/>. Solar City merged with Tesla, a leader in battery technology, in 2016.

³⁵⁸ Under the PPA option, the alternative energy system developer installs the system on a customer's premises while maintaining ownership and performing maintenance and operations functions of that system. The electricity generated is then sold to the consumer through a power purchase agreement.

³⁵⁹ The term "customer-generator" is defined at 73 P.S. § 1648.2; See also, Regs. § 75.1.

³⁶⁰ http://www.puc.state.pa.us/Electric/pdf/AEPS/Net_Metering-Interconnection_Report_2015-17.pdf.

³⁶¹ The Level 1 designation applies to inverter-based small generator facilities with a nameplate capacity of 10 kilowatts (kW) or less and the customer's interconnection equipment is certified. Regs. § 75.34.

Compensation paid to and received from customer-generators continues to be controversial from a cost causation and cost recovery point of view.³⁶² The electrons flow both ways as the customer and the EDC exchange electricity. Think of it as a meter that can spin backwards (as the customer generates more electricity than is consumed in the household) and forwards (as the customer's capacity becomes insufficient to meet household needs).³⁶³ At any point in time the distribution company and the customer can be either a seller or a buyer depending on the status of the customer's generation.

The customer is providing a generation function. The distribution company is providing the meter (customer function) and the distribution system (customer/demand classified) to accept the customer's outflows and then supplies electricity (generation) when needed.³⁶⁴

Compensation is not cost-based. Pennsylvania law requires that "[e]xcess generation from net-metered customer-generators shall receive full retail value for all energy produced on an annual basis."³⁶⁵ Commission regulations implementing this statutory section require the EDC to "credit a customer-generator at the full retail kilowatt-hour rate, which shall include generation, transmission and distribution charges, for each kilowatt-hour produced..."³⁶⁶ If a customer-generator supplies net more electricity in a given month than was consumed (i.e., net balance in the customer's favor), then the excess kilowatt hours are carried forward and credited against subsequent bills (at the full retail rate). Monthly excess kWh is accumulated until the end of the year, at which time the EDC must pay for them at the EDC's price to compare (PTC) rate.

Net metering is controversial. Critics charge that the arrangement encourages excessively-sized customer-owned facilities by over-compensating the resource, creates a cross subsidy to customer-generators, and disfavors customers that do have the capability to deploy (e.g., apartment dwellers) or cannot afford to install distributed generation. Were these facilities

³⁶² A well thought out discussion manual was recently (November 2016) published on this topic by the National Association of Regulatory Utility Commissioners. <http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0>.

³⁶³ Regs. § 75.14(a) and (b) ("A customer-generator facility used for net metering must be equipped with a single bidirectional meter that can measure and record the flow of electricity in both directions at the same rate... If the customer-generator's existing electric metering equipment does not meet the requirements in subsection (a), the EDC shall install new metering equipment for the customer-generator at the EDC's expense.")

³⁶⁴ Transmission functions are not involved for most small generators, except when the utility is the seller.

³⁶⁵ 73 P.S. § 1648.5.

³⁶⁶ Regs. § 75.13(d). Note, this does not include the customer charge.

classified as merchant generators under FERC rules, the compensation received would be less than under the net metering program.

Supporters of net metering assert that the industry is nascent; that public policy should support the development of a diversified base of distributed energy, particularly renewable resources; and that to do otherwise would curtail the development of alternative energy. Generation becomes more resilient when decentralized. Agricultural interests also cite the environmental benefits of methane digesters. Landfill sites can produce electricity from landfill methane.

As the Commission said in 2012, when passing a policy that would limit the sizing of customer-generator facilities compensated by net metering to 110 percent of the customer-generator's annual usage (where a third-party owner/operator is involved):

We do not believe the AEPS Act intended net metering as an avenue for merchant generators to circumvent the wholesale electric market in an attempt to avoid Federal Energy Regulatory Commission jurisdiction. Furthermore, we do not believe it was the intent of the AEPS Act to provide retail rate subsidies to merchant generation facilities at retail customer expense that may result in cross-class subsidization.³⁶⁷

Later, when the Commission sought to codify the 110 percent limitation (later 200 percent) in its regulations, the Independent Regulatory Review Commission determined that the PUC does not possess the statutory authority to impose one and the Commission withdrew the proposal.³⁶⁸

This debate will continue to grow in importance as distributed generation grows.

I. Some Criticisms of RB/ROR Regulation

“All ratemaking is incentive ratemaking. It rewards some patterns of conduct and deters others” Peter Bradford, Chairman, New York Public Service Commission.³⁶⁹

Rate base/rate of return regulation is an asset-based equation. Earnings levels are based upon the value of capital deployed, and thus capital deployment is implicitly encouraged.

³⁶⁷ *Net Metering – Use of Third Party Operators*, Docket No. M-2011-2249441, Final Order (March 29, 2012).

³⁶⁸ *Implementation of the Alternative Energy Portfolio Standards Act of 2004*, Amended Final Rulemaking Order (June 9, 2016).

³⁶⁹ *Regulatory Incentives for Demand-Side Management*: Edited by Steven Nadel, Michael W. Reid, and David R. Wolcott, American Council for an Energy (Sept. 1, 1992), Introduction.

Whether that is good or bad depends upon the desired outcome. At the time that the principles of *Smyth* and *Bluefield* were developed (early 1900s) electricity was in its infancy, and the expansion of the grid was the principal objective. Sales were increasing and marginal costs decreasing. The RR equation was set to establish “just and reasonable” rates. Whether our societal objectives have changed in a way that renders rate base/rate of return regulation outmoded or worse, counterproductive, is a subject of debate and has been for some time.³⁷⁰

One documented criticism is that utilities tend to overcapitalize to increase earnings under the rate base/rate of return model—the so-called “Averch-Johnson Effect”—or more crudely, “gold plating.” The problem is one of excessive capital accumulation, even where decreasing costs might be the better solution:

The essential characteristic to be demonstrated is: if the rate of return allowed by the regulatory agency is greater than the cost of capital but is less than the rate of return that would be enjoyed by the firm were it free to maximize profit without regulatory constraint, then the firm will substitute capital for the other factor of production and operate at an output where cost is not minimized.³⁷¹

The two researchers were also concerned about the temptation to cross subsidize:

Our model suggests that apprehension about the nature of competition in the industry is justified since a common carrier, regulated as described above, would (under certain conditions) have an incentive to operate at a loss in competitive markets and to shift the financial burden to its other services.³⁷²

There are other adverse consequences to rate base regulation. Rate-of-return regulation, by focusing on capital intensity, may impede innovation, but this is difficult to demonstrate. By refusing to pay a higher return, regulation discourages riskier, potentially beneficial, behavior. There is the cost to society of administering the process itself, not only the rate case expense, but the costs of audits and investigations. There is also a school of criticism that argues the

³⁷⁰ Bonbright does a very thorough job of covering these shortcomings in *Principles of Public Utility Rates* (starting on p. 547).

³⁷¹ *Behavior of the Firm Under Regulatory Constraint*, Harvey Averch and Leland L. Johnson, *The American Economic Review* Vol. 52, No. 5 (Dec., 1962), pp. 1052-1069
<http://www.jstor.org/stable/pdf/1812181.pdf?refreqid=excelsior%3Ac78892aff69112a626f44918c7685dce&acceptTC=true>

³⁷² *Id.*

regulators are “captured” by the utilities and that rate cases are a game of over asking and then settling for less to allow the regulators to appear diligent.³⁷³

Increasingly, regulators are focusing on activities that will reduce usage, not expand it; that will reduce the need for utility capital, not increase it; such as conservation, home efficiency, distributed generation, storage, and other demand side measures. These behaviors do not reward the rate-of-return regulated firm. It is one thing to set, monitor, and enforce goals. It is another to align objectives and incentives. Some incentive forms of regulation, such as an enhanced ROE, are discussed elsewhere in this handbook.

J. Setting Revenue Requirement on a Basis Other Than RB/ROR

Rate base/rate of return is not the exclusive means for setting rates. Alternatives have been developed for telephone, water, and city-owned gas systems.

1. PGW “Cash Flow” Method

Philadelphia Gas Works (PGW), managing a city-owned distribution system of approximately 6,000 miles of gas mains and service lines serving approximately 500,000 customers, came under Commission regulation on July 1, 2000, pursuant to the Natural Gas Choice and Competition Act.³⁷⁴ PGW previously had been regulated by the Philadelphia Gas Commission (PGC), a local agency of the City of Philadelphia.

Rather than impose traditional rate base/rate of return regulation on PGW, the Gas Choice Act specified that “the commission shall follow the same ratemaking methodology and requirements that were applicable to the city natural gas distribution operation prior to the assumption of jurisdiction by the commission, and such obligation shall continue until the date on which all approved bonds have been retired redeemed, advance refunded or otherwise defeased.”³⁷⁵ The Management Agreement between PGW and the Philadelphia Facilities Management Corporation (PFMC) defined the ratemaking methodology for the city’s gas utility.

³⁷³ “Put simply, regulatory capture describes the process through which regulated monopolies end up manipulating the state agencies that were designed to control them. Regulatory capture is neither a form of corruption nor control, but rather an element of persuasion.” *Game Over: Regulatory Capture, Negotiation, and Utility Rate Cases in an Age of Disruption*, Heather Payne, University of San Francisco Law Review, Vol. 52 (July 6, 2017) (available at SSRN: <https://ssrn.com/abstract=3025917>).

³⁷⁴ Code § 2212(b).

³⁷⁵ Code § 2212(e)

Prior to the Gas Choice Act, PGW had not increased gas rates since 1991. Since assuming jurisdiction, the Commission has approved approximately \$170 million of annual base rate relief requests by PGW.

In 2001, PGW's first base rate case, the Commission decided that the statute required a debt service coverage form of ratemaking:³⁷⁶

Section 2212(e) of the Act obligates the Commission not to take an action that would adversely affect the debt service coverage of PGW's bonds. This requirement has the effect of imposing a statutory floor that the Commission has carefully considered in adjudicating this matter. In order to determine the appropriate rate increase, the Commission is required to ensure that PGW is able to maintain an adequate level of financial health required to fund operations and meet debt service requirements.³⁷⁷

At the same time, the Code § 1301 standards of "just and reasonable" rates apply:

...in following the cash flow method, the Commission is free to examine PGW's rates under the just and reasonable standard. The Commission is not required to accept the level of expense claimed by PGW or approved in a PGW budget by the PGC. If PGW fails to prove that a given expense item was prudently incurred and reasonable in amount, the Commission will make an appropriate adjustment in its rates chargeable to customers.³⁷⁸

In reviewing the evidence presented in that case, the Commission concluded that:

So long as PGW refrains from incurring expenses that are imprudent or unreasonable in amount, consistent with the determinations in this order, we expect that an allowable annual revenue requirement increase of \$28 million over PGW's existing rates will allow PGW to satisfy its debt service coverage requirements. Specifically, the increased revenues allowed by this order, indicate that debt service coverages will be approximately 2.87 coverage for the 1975 ordinance bonds and approximately 3.01 coverage for the 1998 ordinance senior

³⁷⁶ While the PGW/PFMC Agreement, and now the PUC, label it as a "cash flow method" of ratemaking, this is actually a misnomer. As described further in this section, it is a debt service coverage-based ratemaking methodology.

³⁷⁷ *Pennsylvania Public Utility Commission v. Philadelphia Gas Works*, Docket No. R-00006042, Opinion and Order (Oct. 4, 2001) at 43, affirmed *City of Philadelphia v. Pa. PUC*, 829 A.2d 1241 (Pa. Commw. Ct. 2003) ("We hold that the approach described above satisfies the Gas Choice Act directive to follow the same ratemaking methodology and requirements. The PUC committed no clear error when it adopted this approach."). The court also rejected the claim that approval of the rates by City Council and the PGC was also a precondition to the effectiveness of rates.

³⁷⁸ *Id.* at 15.

bonds. Furthermore, coverage for the 1998 ordinance subordinate bond will be more than adequate.³⁷⁹

In 2010, the Commission issued a policy statement more fully setting forth these criteria and the financial and other considerations that are to be examined in setting PGW's base rates at just and reasonable levels.³⁸⁰ In its Policy Statement, the Commission described the requirements of the Cash Flow Method as follows:

The Commission is obligated under law to use the cash flow methodology to determine PGW's just and reasonable rates. Included in that requirement is the subsidiary obligation to provide revenue allowances from rates adequate to cover its reasonable and prudent operating expenses, depreciation allowances and debt service, as well as sufficient margins to meet bond coverage requirements and other internally generated funds over and above its bond coverage requirements, as the Commission deems appropriate and in the public interest for purposes such as capital improvements, retirement of debt and working capital.³⁸¹

In addition to debt service coverage, the Commission also stated in the policy statement that it would consider, among other relevant factors, the following financial factors:³⁸²

- PGW's test year-end and (as a check) projected future levels of non-borrowed year-end cash.
- Available short-term borrowing capacity and internal generation of funds to fund construction.
- Debt-to-equity ratios and financial performance of similarly-situated utility enterprises.
- Level of financial performance needed to maintain or improve PGW's bond rating, thereby permitting PGW to access the capital markets at the lowest reasonable costs to customers over time.

The Commission is obligated to establish rate levels adequate to permit PGW to satisfy its bond ordinance covenants, the most important of which is the debt service coverage covenant.³⁸³ Debt service coverage ratio is a financial metric used to determine a company's

³⁷⁹ *Id.* at 43-44.

³⁸⁰ Reg. §§ 69.2701-2703.

³⁸¹ Reg. § 69.2702b).

³⁸² Reg. §§ 69.2703(a), (b).

³⁸³ Code § 2212(e); Reg § 69.2703(b). *See also Pennsylvania Public Utility Commission v. Philadelphia Gas Works*, Docket No. R-00006042, Opinion and Order (October 4, 2001) at 43, affirmed *City of Philadelphia v. Pa. PUC*, 829

ability to generate enough income in its operations to cover annual debt expenses (interest and principal). The formula is net operating income divided by debt service. PGW's debt is financed through bonds issued by the city. The city's General Ordinances require that PGW maintains a minimum debt service coverage ratio of 1.5 times on debt issuances. So, if PGW's net income were set at \$196 million and its total debt service were \$107 million, the resulting coverage ratio would be 1.82x and sufficient to meet its debt covenants.

The process of arriving at debt-to-equity levels and level of financial performance employs the methods of a traditional rate base/rate of return case, including a test year and various proforma adjustments. No depreciation expense is included in rates, because both principal and interest are included in the debt service portion. The principal payment would be the return of the cost of the asset (depreciation expense), and interest would be the return on the asset (or ROR) under normal rate base/rate of return treatment. There is, however, no calculation of rate base or a rate of return. Interest paid on the outstanding debt is treated as an expense. So, too, is the \$18 million paid to the city annually as a lease payment (or, alternatively, as an equity dividend).³⁸⁴ As noted above, net expense is set to meet the minimum coverage requirements plus an additional "reasonable" amount to insure sufficient cash flow and to maintain or improve PGW bond rating. The net income over and above debt service obligations then becomes internally generated capital that is used for construction and other purposes.

Otherwise, PGW's operations are treated like the privately-owned, regulated gas companies. PGW recovers a portion of its capital investment spent on modernizing its distribution system through the DSIC/LTIIP mechanism.³⁸⁵ It maintains a fuel clause. PGW also has been permitted to employ a "weather normalization clause" that permits it to recover (or credit) any differences between its "weather normalized" level of gas sales and its experienced levels, on an annual basis. Like investor-owned utilities, PGW provides a cost of service study in rate cases that allocates plant in service, depreciation expense, return dollars, and net income by class so the Commission can determine if the revenue received from each class is more or less than the cost of providing service to that class.

A.2d 1241 (Pa. Commw. Ct. 2003) ("...the Commission is required to ensure that PGW is able to maintain an adequate level of financial health required to fund operations and meet debt service requirements.").

³⁸⁴ See Code § 2212(f).

³⁸⁵ PGW's DSIC does not use the rate base x ROR methodology that is used in the DSICs of traditional utilities.

2. Telephone Price Caps

Chapter 30 was added to the Code in 1993 by Act 67³⁸⁶ and subsequently reenacted in 2004 under Act 183.³⁸⁷ Chapter 30 aided the transition of the telecommunications market from monopoly status to a competitive model by encouraging overlapping service territories, accelerating broadband deployment, setting procedures for competitive service designation by the incumbent, and deregulating long-distance service.

In exchange for accelerated broadband deployment by an incumbent local exchange company (ILEC), Chapter 30 authorized the Commission to approve petitions for “a streamlined form of regulation” that allows for formula-based rates.³⁸⁸ Almost all ILECs³⁸⁹ have elected to deploy, and the form of regulation has been of two types: price caps or a simplified form of rate base/rate of return regulation. Each ILEC designed and proposed a form of regulation in its individual “Chapter 30 Plans” that have received Commission approval. The price cap formulas approved by the PUC are not all the same, and various idiosyncrasies apply. There are also special procedural rules contained in the Plans that supplant the Commission’s normal rate case procedures.

Generally speaking, price cap formulas yield a percentage factor that is applied to the company’s prior period intrastate, non-competitive (regulated) revenues to produce a dollar increase. Subject to certain consumer protections, such as an annual cap on local service (dial tone) increases, the company then collects the allowed revenue increase by raising rates or, as an alternative, may “bank” the allowed increase for some period.³⁹⁰

The price cap formula is fairly straightforward. The first filer, Verizon PA, received approval for the basic price cap mechanism:

³⁸⁶ Code §§ 3001 – 3010 (Repealed). <http://www.legis.state.pa.us/WU01/LI/LI/US/HTM/1993/0/0067..HTM>.

³⁸⁷ Code § 3011 et seq.

³⁸⁸ Code § 3006 (Repealed) (“The streamlined form of rate regulation shall be designed to decrease regulatory delays and costs and may include, but is not limited to, use of an index formula, price stability plan, zone of rate freedom or a combination thereof. The streamlined form of rate regulation may be proposed to revise or decrease notice periods, suspension periods and other procedures currently required by Chapter 13 (relating to rates and ratemaking) consistent with due process requirements.”).

³⁸⁹ Four very small companies—Deposit, West Side, Hancock, and Citizens (New York)—whose switches are located in an adjacent state, have been exempted.

³⁹⁰ Some plans allow indefinite banking. Some are limited to 4 years.

$$\text{Price Change Opportunity} = \text{Revenues} \times (\text{GDP-PI} - 2.93\%)$$

Where:

Price Change Opportunity = Authorized annual decrease or increase

Revenues = Intrastate noncompetitive service revenue amount billed for the twelve-month period corresponding to that used to measure the annual change in the GDP-PI.

GDP-PI = The percentage annual change in the Gross Domestic Product-Price Index.

Verizon’s original 2.93 percent “productivity offset” has since been reduced to 0.5 percent.³⁹¹

Commonwealth Telephone (now Frontier), on the other hand, has a slightly more complicated formula and no offset:

$$\text{PSIt} = \text{PSIt-1} \times [1 + \Delta\text{GDP-PIt-1} \pm Z]$$

Where:

PSIt = The new maximum change in price for the non-competitive service category for the current twelve-month period.

PSIt-1 = The current maximum change in price for the non-competitive service category for the previous twelve-month period.

$\Delta\text{GDP-PI}$ = The percent change in the Gross Domestic Product Price Index based on the quarter ending six months prior to the effective date of the new annual tariff and the corresponding quarter of the previous year.

Z = The effect of any exogenous changes.

The main difference from the Verizon PA plan is the inclusion of a “Z” factor.

The central idea behind a price cap methodology is to control the *price* a company charges, rather than its earnings. The Gross Domestic Product Price Index (GDP-PI) is the market value of all final goods and services produced within the U.S.³⁹² The idea of an offset is to capture industry-specific price deflation (e.g., the cost of an internet protocol-based switch is less than the older switches being replaced) or as a spur to the company to wring greater efficiencies from its operations. No offset, as in the Commonwealth Telephone example, means that the company can raise its prices at the same rate as aggregate prices nationally. With a positive 2.93% offset during its initial plan period, Verizon gave back millions to customers in price reductions, because inflation, as measured by GDP-PI, was lower than the offset. The other

³⁹¹ Code § 3015(a)(ii).

³⁹² This not like the consumer price index (CPI), which measures the level of prices in the economy and compares them to previous years based on a fixed basket of goods that an average person buys each year (but excludes some).

variable, the Z or exogenous factor, is designed to capture regulatory or legislative changes that affect revenues or expenses to the extent not captured in GDP (i.e., that affect the telecommunications sector particularly or with greater impact).

The results are tabulated annually. So, starting at 100 (i.e., starting rates), the subsequent year's PSI changes are tracked and accumulated. In year 2, were GDP-PI at 2.0 percent and no offset applied, the PSI would be 102. The resulting PSI, or PCO in Verizon's case, is next compared to the increases taken in the past.

The Service Price Index (SPI) reflects the aggregate price changes taken in prior years and tracks the actual total changes in the price for noncompetitive services. Commonwealth's SPI formula is stated as:

$$SPI_t = SPI_{t-1} [\sum_i v_i (P_t/P_{t-1})]$$

Where:

SPI_t = The proposed new SPI value.

SPI_{t-1} = The existing SPI value as of the last approved tariff filing.

P_t = The proposed price for rate element "i".

P_{t-1} = The existing price for rate element "i".

v_i = The current estimated revenue weight for rate element "i", calculated as the ratio of the base period demand for the rate element "i" priced at the existing rate, to the base period demand for all noncompetitive services priced at existing rates.

Again, the starting point is 100. If the PSI is 102, as in the example above, the company could raise rates to produce 2 percent more revenue, resulting in a new SPI of 102. The SPI may never exceed the PSI, because the rate increase would exceed the allowed revenue.

There are other intricacies, but these are the basics. As noted in the operations section of this handbook, the Commission's rate setting jurisdiction only extends to stand-alone local service (dial tone) that are not part of a bundle and ancillary services (e.g., installation and restoration).

3. Small Water/Wastewater Company Operating Ratio

In 1996, the Commission announced that it would make available a simplified form of ratemaking to water or wastewater utilities with gross revenues of less than \$250,000 annually, in response to financial and operational challenges of these small companies:

There is a continuing crisis for small water and wastewater utilities in the Commonwealth due to several recurring factors. First, small companies have problems of economy of scale, management, and access to capital that do not weigh as heavily upon larger companies. Secondly, all water and wastewater utilities, but especially the smaller companies, have been hard pressed to meet the increasingly stringent requirements of environmental legislation and regulation. Third, navigating the sometimes highly complex, technical and arduous process of public utility ratemaking can challenge even a well-funded utility with expert legal assistance. Small companies may find that their relatively modest requests for rate relief are largely eaten up, or even dwarfed, by the cost of preparing technical and legal submissions that are required in a traditional, full-blown, rate base/rate of return proceeding.

The greatest regulatory problem with the rate base/rate of return paradigm is presented when a small water or wastewater utility has little or no rate base on which to base a return. That circumstance may come about in several different ways. An older utility may have reached full depreciation of its plant (mains, buildings, and the like) over the years, or the utility may have been constructed largely with customer contributions.³⁹³

The Commission found that Code § 1311 (specifying original cost valuation) was not violated if there was no rate base employed (“that provision is permissive rather than prohibitory”). The operating ratio methodology had been used previously and was affirmed by the Commonwealth Court.³⁹⁴

Commission regulations specify that:

The operating ratio at present rates shall be calculated as a ratio of operating expenses to operating revenues, where the numerator shall include operations and maintenance expense, annual depreciation on non-contributed facilities, amortization of multiyear expenses and applicable taxes and the denominator shall consist of the utility’s operating revenues at present rates.

An increase or decrease in operating revenues shall be determined by dividing the utility’s reasonable and legitimate operating expenses by the target operating ratio...and subtracting that amount from the test period operating revenues.³⁹⁵

³⁹³ 27 Pa.B. 301.

³⁹⁴ *Popowsky v. Pa.P.U.C.*, 674 A.2d. 1149 (Cmwlth. Ct. 1996). The court found that the Legislature has given the Commission considerable latitude to determine the appropriate rate setting methodology in any particular case and that the Public Utility Code does not limit the PUC’s discretion to use methodologies other than rate base/rate of return.

³⁹⁵ Regs. §§ 53.54(b)(1) and (3).

The appropriate ratio is not specified in the regulations. What appears, rather, is a list of factors to be considered, such as:

- The operating ratios of comparable utilities.
- The resulting interest coverage.
- Comparison of the cost of service of similar companies not employing an operating ratio rate methodology.
- Current market conditions, including price inflation.
- The quality of service and efficiency of operations.
- Financial resources.
- The fairness of the resulting return.³⁹⁶

Although the operating ratio method is not often used by utilities when setting rates, historically, the Commission has approved operating ratios of 85-90 percent for these companies.³⁹⁷ So expenses of \$100 and a 90% ratio would yield a revenue requirement of \$111 (rounded). Allowed expenses include direct operating expenses and debt service, as well as providing an allowance to cover abnormal expenses or repairs to the system that typically do not occur on an annual basis. There is no return on investment. The difference between the ratio and 100 percent is the net income allowed (i.e., \$11 in the example).

IV. CONCLUSION

Change is what makes utility rate setting both interesting to follow and difficult to encapsulate at any one particular time. The regulated utility industry is neither isolated nor static. As technology and the economy develop and change, so, too, utilities and regulators will adapt and change the assets used; the products sold; and, more relevant to this handbook, the pricing structures and regulations that help to ensure safe and reliable service at just and reasonable rates.

Although every effort has been made to provide a comprehensive view of utility ratemaking, it is inevitable that change will cause some of the subject addressed to become irrelevant or outdated. It is hoped that this tome of accumulated knowledge will provide a deep

³⁹⁶ Regs. § 53.54(b)(2).

³⁹⁷ See, for example, *Pennsylvania Public Utility Commission v. Andreassi Gas Company*, Docket No. R-2016-2567893, Order (December 22, 2016).

enough understanding of the elements of utility ratemaking to enable the reader to evolve with the change that will inevitably occur.

ACCOUNTING PRINCIPLES

A utility, like any other business, is an independent organizational entity. The books and records of a corporation are kept in the name of the corporation rather than in the name of the owners. Each corporation has business transactions that must be recorded, sorted, summarized, and reported. Accounting is no more than a method of compiling this data in a usable form. Broadly defined, accounting is “the process of identifying, measuring and communicating economic information to permit informed judgments and decisions by users of the information.”³⁹⁸ Owners and prospective owners, bankers, vendors, and governmental agencies are among those who use this information.

Accounting is commonly understood as the accumulation of numbers, which, when properly summarized and presented, give a specific result. However, it is important to recognize that accounting involves judgment. While it may be true that A plus B equals C, judgment is required to determine what is to be A, what is to be B, and what C means, once determined. This use of judgment can lead to different, even conflicting, interpretations of the same set of data. It is important when reading any report to ask: “What is the purpose of the report? For whom was it prepared? Who prepared it?”

Utilities provide a variety of accounting reports to a myriad of groups for many purposes. An Annual Report to Shareholders, which includes uses of funds, is sent to all shareholders and any other interested party requesting the document. Utilities must also file annual reports with the federal Securities and Exchange Commission (SEC). The most important is the SEC Form 10-K, which provides audited financial statements, a 5-year comparative summary of operations, and other salient information. Others include the Federal Energy Regulatory Commission (FERC) FERC Form 1 (Electric) and Form 2 (Gas). The Federal Communications Commission (FCC) requires a host of data and publishes reports on a variety of telecommunications topics. Multiple reports must also be filed with the Pennsylvania Public Utility Commission, including annual financial reports, long range forecasts, accident reports, contracts with affiliates, etc.

³⁹⁸ *A Statement of Basic Accounting Theory* (Evanston Ill.; American Accounting Association), p. 1.

While much of the information may be supplied in the rate filing itself, these other sources of material are available for review and analysis.

I. Balance Sheet

The balance sheet presents the financial picture of a company’s assets, liabilities, and capitalization at a point in time; usually December 31st of a given year. The company may prepare such statements at other intervals throughout the business operating cycle, such as monthly or quarterly. The balance sheet is usually prepared on a comparative basis with the same point in time of the prior year. This comparison is, in part, a check that consistent accounting methods have been used, but more importantly reflects the changes in the assets, liabilities, and capital accounts during the period of operations between the two dates of the balance sheet. Differences resulting from changes in accounting methods will normally be disclosed, and explanations will appear in the footnotes.

For regulatory purposes, the balance sheet is prepared in two sections with the first setting forth the assets, including the company’s fixed assets, current assets, and deferred charges. The second section sets forth the equity and liabilities, including current liabilities and non-current liabilities, such as deferred and other credits, and typically would appear as follows:

<u>Assets</u>		<u>Equity and Liabilities</u>	
Utility Plant (Fixed Assets)	_____	Equity Capital	_____
Net Utility Plant	_____	Long-Term Debt	_____
Other Property & Investments	_____	Current & Accrued Liabilities	_____
Current & Accrued Assets	_____	Deferred and Other Credits	_____
Deferred Debits	_____	Contributions in Aid of Construction	_____
TOTAL	\$ _____		\$ _____

In general terms, balance sheet asset items are composed of the following:

- Non-current assets, primarily composed of fixed assets, also include the “long-term” portion of such items as deferred tax assets, lease receivables, other financial assets, and other assets. The company’s fixed assets include four general categories of utility property defined as Utility Plant in Service, Utility Plant Held for Future Use, Construction Work in Progress, and Non-Utility Property.
- Utility Plant in Service is investment in the original cost of assets devoted to public service and includes intangible assets (such as franchises and rights) and tangible assets (including land, buildings and structures, production facilities—such as treatment and pumping plants, communication networks, transmission and distribution

facilities and customer service connections, metering devices, transportation equipment, tools, and other work and office equipment).

- Utility Plant Held for Future Use is the original cost of facilities of the same general categories as Utility Plant in Service but not yet devoted to public service.
- Construction Work in Progress is the cost of Utility Plant in the process of construction or completion, of which all or part is not yet devoted to public service.
- Non-Utility Property is investment in fixed assets not required for rendering utility service to the public.
- Current assets. Included in the company's current assets are cash and other tangibles that will be turned into cash or fixed assets or used in providing customer service within a reasonably short period, usually 1 year or less. Current assets include: cash; temporary cash investments of idle or excess cash; accounts receivable from ratepayers or others for utility services rendered or for other miscellaneous services or sales; interest receivable from investments or other miscellaneous sources; accrued revenues from ratepayers for utility services rendered but not billed to the ratepayer; materials and supply inventories to be used for construction, operating supplies, or maintenance of facilities; and prepayments of taxes, insurance, or other operating expenses.
- Deferred charges include expenses incurred that apply to future periods of operation, e.g., costs associated with debt financing, abnormal maintenance projects to be absorbed as a cost in future operations due to extended intervals or expected life of the project, and other miscellaneous deferred items to be disposed of in (or over) future periods.

Balance sheet capitalization is generally composed of the following:

- Capitalization. The capitalization section includes the sources of permanent funds that primarily provided the fixed assets and working capital necessary to rendering public utility service. The sources of such capital include common equity, preferred stock, and long-term debt. Retained earnings are also displayed on the equity section of the balance sheet.

Balance sheet liabilities are generally composed of the following:

- Non-current liabilities. This section of liabilities represents amounts attributable to liability accounts (e.g., borrowings, other financial liabilities, retirement benefit obligation, deferred tax liabilities, etc.) representing amounts due beyond 1 years' time.

- **Current liabilities.** This section of liabilities represents obligations of the company due within 1 year and includes accounts payable, the current portion of long-term debt obligations, customer deposits, taxes, interest on debt obligations, tax collections payable, and other miscellaneous liabilities. Accounts payable include amounts due creditors for services or materials arising from the day-to-day operation of the business. The current portion of long-term debt includes long-term debt obligations maturing within 1 year and contractual annual long-term debt reductions (sinking fund payments). Taxes include amounts due governmental authorities for payroll, real estate, and taxes on income and receipts, as well as taxes collected from employees and ratepayers for governmental agencies.
- **Accrued interest** is the amount due on debt obligations, customer deposits, bank notes, and other interest-bearing obligations.
- **Deferred credits.** These liabilities represent funds received from customers as advances toward construction, generally to be refunded over some future period; deferred income taxes and credits; and other miscellaneous deferred credits.
- **Contributions in aid of construction** represent funds received from ratepayers or others used for the construction or acquisition of Utility Plant in Service.

An example of a format of Typical Utility's balance sheet might appear as follows:

Typical Utility, Inc.
Balance Sheet as of December 31, 2015 and 2016

Assets	2016	2015	Increase (Decrease)
Property, Plant, and Equipment			
Utility Plant in Service	\$ 75,600,000	\$ 76,308,000	\$(708,000)
Construction Work in Progress	375,000	350,000	25,000
Accumulated Depreciation	(18,675,000)	(18,008,000)	(667,000)
Utility Plant Acquisition Adjustment	1,500,000	1,500,000	-
Total Utility Plant (net)	58,800,000	60,150,000	(1,350,000)
Current Assets			
Cash and Cash Equivalents	10,000	90,000	(80,000)
Working Funds	2,000	2,000	-
Accounts Receivable (net)	627,000	450,000	177,000
Materials and Supplies	75,000	70,000	5,000
Prepayments and Other	75,000	72,000	3,000
Total Current Assets	789,000	684,000	105,000
Deferred Debits			
Other	25,000	14,000	11,000
Total Deferred Charges	25,000	14,000	11,000
	\$ 59,614,000	\$ 60,848,000	\$ (1,234,000)

<u>Capitalization and Liabilities</u>			
Capitalization			
Common Equity	\$ 17,000,000	\$ 17,000,000	-
Retained Earnings	<u>8,290,000</u>	<u>7,980,000</u>	<u>310,000</u>
Total Equity	25,290,000	24,980,000	310,000
Long-Term Debt	<u>21,500,000</u>	<u>22,810,000</u>	<u>(1,310,000)</u>
Total Capitalization	<u>46,790,000</u>	<u>47,790,000</u>	<u>(1,000,000)</u>
Current and Accrued Liabilities			
Short-Term Debt	36,500	42,000	(5,500)
Current Portion of Long-Term Debt	436,500	571,000	(134,500)
Accounts Payable	870,000	870,000	-
Customer Deposits	6,000	6,000	-
Taxes Accrued	545,000	505,000	40,000
Interest Accrued	250,000	249,000	1,000
Other Current Liabilities	<u>455,000</u>	<u>465,000</u>	<u>(10,000)</u>
Total Current Liabilities	<u>2,599,000</u>	<u>2,708,000</u>	<u>(109,000)</u>
Deferred Credits			
Customer Advance for Construction	950,000	950,000	-
Deferred Income Tax	6,900,000	7,000,000	(100,000)
Other Deferred Credits	<u>175,000</u>	<u>200,000</u>	<u>(25,000)</u>
Total Deferred Credits	<u>8,025,000</u>	<u>8,150,000</u>	<u>(125,000)</u>
Contributions in Aid of Construction	<u>2,200,000</u>	<u>2,200,000</u>	<u>-</u>
	<u>\$ 59,614,000</u>	<u>\$ 60,848,000</u>	<u>\$ (1,234,000)</u>

The assets and liabilities on the balance sheet change from day to day, with the individual accounts increasing or decreasing with each business transaction. Every business transaction affects a minimum of two balance sheet accounts. For example, if the company obtained a loan from a bank as a note payable, a credit entry (increase) is made in the current liabilities section of the balance sheet, and a debit entry is made to the current asset section (increase cash) to reflect the new liability and the new or additional cash asset. Further, if the cash received is used to acquire new Utility Plant in Service, the next entries will be a credit (decrease) to the cash current asset and a debit (increase) to Utility Plant fixed assets. As a result of the dual entry nature of balance sheet account, the total assets must equal the total liabilities.

II. Statement of Income

The Statement of Income is the financial statement prepared in conjunction with the balance sheet, which sets forth the income from operations for the period stated, normally a twelve-month period or one operation cycle. Basically, the statement provides information concerning the source and amount of income, the deductions or expenses from income, the results of system operations, the cost of service capital and other debt, and the extent to which the common equity investors have realized gain or loss during the period covered by the report.

The statement includes four general areas of reporting to arrive at net income for the period, including: operating revenues, operating expenses, other income and deductions, and interest charges. Net income is derived by subtracting the deductions from operating revenues and will appear as follows:

Operating Revenues	\$ _____
Operating Expenses	_____
Total Operating Expenses	_____
Operating Income	_____
Other Income and Deductions	_____
Income Before Interest	_____
Interest Charges	_____
Total Interest Charges	_____
Net Income	\$ _____

The net income is further reduced by the amount of preferred stock dividend requirements. The balance remaining reflects an increase or decrease in the retained earnings portion of common equity reflected on the balance sheet.

Following are brief statements concerning the components of the statement of income.

- Operating revenues represent sales to ratepayers for utility service rendered applicable to the period covered by the statement. The sales are generated in compliance with the company's approved tariff for utility service and other charges to its ratepayers.
- Operating expenses include: labor and associated costs of employee benefits, fuel or power purchased, chemicals, rents, transportation expenses, meter reading expenses, and administrative and general expenses, including record keeping and reporting.
 - Maintenance expenses include repairs to the company's utility plant used and useful in rendering service to ratepayers. The prescribed system of accounts

also provides for segregation of maintenance expenses into categories defined for the various classes of utility plant in service.

- Depreciation expense can be broadly described as the loss in service value of utility plant assets not restored by current maintenance, which will cause the ultimate retirement of the property. Among the causes of loss in service value are: wear and tear, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities. The expense is calculated for the loss in service value for the period covered by the statement of income.
- Taxes other than income taxes include taxes imposed by governmental agencies for real estate and personal property, gross receipts, and other taxes, including those imposed by state and federal agencies on income of the company and its employees. Income taxes include taxes imposed by state and federal agencies on income accrued during the period covered by the statement of income.
- Operating income is the revenue or income remaining after deduction of operating expenses and represents the income available to service the capital costs of the utility. Stated differently, operating income is the income generated from sales to ratepayers using the utility plant assets necessary to provide utility service after deduction of all operating expenses necessary to provide utility service.
- Other income and deductions include income and expenses not properly includable in the categories of revenues and expenses directly related to providing utility service. Such income and expenses will be non-utility in nature.
- Interest charges include: interest on the long-term debt portion of the capitalization, amortization of costs incurred in connection with issuance of long-term debt, and other interest costs pertaining to short-term debt and customer security deposits.
- Net income is determined after deducting interest charges from income and represents the earnings of the company available to the common stockholders (after provision is made for preferred stock dividend requirements). The earnings so determined will be recorded in retained earnings on the balance sheet and become available for dividends to the common stockholders and/or remain as additional common equity investment.

The format for a statement of income for Typical Utility might appear as follows:

Typical Utility, Inc. Statement of Income <u>Twelve Months Ended Dec. 31, 2015 and 2016</u>			
	2016	2015	Increase (Decrease)
Operating Revenues	\$ 7,800,000	\$ 8,100,000	\$(300,000)
Expenses			
Operating Expenses	3,898,000	3,900,000	(2,000)
Depreciation Expense	1,600,000	1,750,000	(150,000)
Amortization	31,000	32,000	(1,000)
Taxes Other than Income	390,000	405,000	(15,000)
Income Taxes	312,000	324,000	(12,000)
Total Operating Expenses	6,231,000	6,411,000	(180,000)
Operating Income	1,569,000	1,689,000	(120,000)
Other Income and Deductions (net)	(78,000)	(76,000)	(2,000)
Income Before Interest Charges	1,491,000	1,613,000	(122,000)
Interest Charges			
Interest on Long-Term Debt	1,062,500	1,120,500	(58,000)
Amortization of Debt Expense	19,000	20,000	(1,000)
Total Interest Charges	1,081,500	1,140,500	(59,000)
Net Income	\$ 409,500	\$ 472,500	\$ (63,000)

III. Statement of Retained Earnings

The Statement of Retained Earnings covers a specific period in time (the accounting period). This statement reports how net income and the distribution of dividends affect a company's financial position during that period. Net income during the accounting period increases the retained earnings balance, and a declaration of dividends to shareholders decreases it. The related equation is: Beginning Retained Earnings + Net Income – Dividends = Ending Retained Earnings.

Typical Utility, Inc.
Statement of Retained Earnings
For the Twelve Months Ended Dec. 31, 2016

Retained Earnings, Jan.1, 2015	\$ 7,980,000
Net Income	<u>409,500</u>
	8,389,500
Less Dividends	<u>99,500</u>
Retained Earnings, Dec. 31, 2016	<u><u>\$ 8,290,000</u></u>

IV. Statement of Cash Flows

The Statement of Cash Flows divides cash inflows and outflows (receipts and payments) into three primary categories of cash flows in a typical business: cash flows from operating, investing, and financing activities. Like the statement of income, it covers a specific period of time, usually 1 year. Individual line items under each of the three primary categories can be positive or negative:

- +/- Cash Flows from Operating Activities
- +/- Cash Flows from Investing Activities
- +/- Cash Flows from Financing Activities

Change in Cash

Typical Utility, Inc.
Statement of Cash Flows
For the Year Ended December 31, 2016

Cash Flows from Operating Activities	
Net Income	\$ 409,500
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities	
Depreciation and Amortization	1,631,000
Deferred Income Taxes	(100,000)
Other Deferred Credits	(25,000)
(Increase) Decrease In	
Accounts Receivable	177,000
Materials and Supplies Inventory	5,000
Prepayments	3,000
Other Deferred Debit	11,000
Increase (Decrease) In	
Accounts Payable	-
Accrued Taxes	40,000
Accrued Interest Payable	1,000
Net Cash Provided by Operating Activities	<u>2,152,500</u>
Cash Flows from Investing Activities	
Additions to Utility Plant in Service, Net of Salvage	(708,000)
(Increase) Decrease to Construction Work in Progress	25,000
Net Cash (Used) by Investing Activities	<u>(683,000)</u>
Cash Flows from Financing Activities	
Retained Earnings	310,000
Dividends Paid	(99,500)
Decrease in Short-Term Debt	(5,500)
Current Portion of Long-Term Debt	(134,500)
Decrease in Long-Term Debt	(1,310,000)
Other Current Liabilities	(10,000)
Net Cash Provided (Used) by Financing Activities	<u>(1,549,500)</u>
Cash Increase (Decrease) in Cash and Cash Equivalents	\$ (80,000)
Cash and Cash Equivalents at Beginning of Year	\$ 90,000
Cash and Cash Equivalents at End of Year	\$ 10,000

V. Analysis of Financial Information

The financial condition and the results of operations of a business enterprise are of interest to many groups. The balance sheet, income statement, statement of retained earnings, and statement of cash flows, together with supplementary statements and schedules, present much of the basic information needed to review and analyze the financial condition and operating results of a company.

The use of comparative analysis is facilitated by the long-standing accounting principle of consistency. An auditor is expected to include in his/her report on the company's financial statements his/her opinion as to whether the financial results are stated in conformity with generally-accepted accounting principles applied on a basis consistent with the preceding year. If consistency is not maintained, the auditor is expected to call attention to any material changes in practice that have taken place.

The usual presentation of financial statements includes the results of the most current period with the results of the most recent similar period. The balance sheet as of Dec. 31, 2017 would be presented with the balance sheet as of Dec. 31, 2016. The income statement for year ending Dec. 31, 2017 would be presented with the income statement for the year ended Dec. 31, 2016. In addition, the financial statements may contain information for prior periods, such as a balance sheet for Dec. 31, 2015 or 2014 or an income statement for each of the preceding 5 years. The more information one has about a company over time, the better the picture of the company. Comparison of data will serve to point out any irregularities or divergence from an established pattern, which may require further investigation and information.

VI. Adjustments

Financial statements presented as evidence in a utility rate case to aid the regulatory decision-making process serve many purposes. They should fairly and accurately present the operating results from revenues derived from the company's present schedule of rates and charges and as adjusted to reflect the operating results from the new proposed schedule of rates and charges. The statements will also reflect the capital investment in the company that provided the funds for the utility plant necessary to render the utility service to the public. The methods employed to determine the appropriate cost of this capital investment are discussed in this

handbook, as are methods to determine the utility plant investment (rate base) devoted to public service, all a part of the ratemaking formula.

Since the utility ratemaking process sets rates and charges for future periods of operations, and such rates and charges are expected to be in effect for some reasonable future period, it is essential that the basis for establishing such new rates and charges be based on the most current financial information available and that this information also be presented as adjusted to reflect known and measurable changes in revenues, expenses, capital costs, and utility plant investment for the foreseeable future.

Glossary of Terms

A – Ampere
AEC – Alternative Energy Credits
AFUDC – Allowance for Funds Used During Construction
ASC – Accounting Standards Codification
Bcfd – billion cubic feet per day
BI&E – Bureau of Investigation and Enforcement
CAPM – Capital Asset Pricing Model
Ccf – One Hundred Cubic Feet
CHP – Combined Heat and Power
CIAC – Contributions in Aid of Construction
CLEC – Competitive Local Exchange Carrier
DA – Day-Ahead
DCF – Discounted Cash Flow
DER – Distributed Energy Resources
DG – Distributed Generation
DSIC – Distribution System Improvement Charge
DSP – Default Service Provider
ECR – Energy Cost Rate
EE&C – Energy Efficiency and Conservation
EDC – Electric Distribution Company
EGS – Electric Generation Supplier
FERC – Federal Regulatory Energy Commission
FERC Formula – 45-Day Rule
FPFTY – Fully Projected Future Test Year
FTY – Future Test Year
HTY – Historic Test Year
ILEC – Incumbent Local Exchange Carrier
ISO – Independent System Operator
IXC – Independent Interexchange Carrier
kW – Kilowatt
kWh – Kilowatt hour
LDC – Local Distribution Company
LTIIIP – Long-Term Infrastructure Improvement Plan
Mbps – Megabits Per Second
Mgal – One Thousand Gallons
NGDC – Natural Gas Distribution Company
NGL – Natural Gas Liquid
NGPA – Natural Gas Policy Act
NGS – Natural Gas Supplier
O&M – Operating and Maintenance
OALJ – Office of Administrative Law Judge
OCA – Office of Consumer Advocate
OPEC – Organization of Petroleum Exporting Countries
OSA – Office of Special Assistants
OSBA – Office of Small Business Advocate

PJM – Pennsylvania-New Jersey-Maryland Interconnection
PTC – “Price to Compare”
PV –Photovoltaic
RB – Rate Base
RDS – Residential Distribution Service
ROR – Rate of Return
RR – Revenues
RT – Real Time
RTO – Regional Transmission Operator
SEC – Securities and Exchange Commission
SFV – Straight Fixed Variable
SPI – Service Price Index
STAS – State Tax Adjustment Surcharge
TNC – Transportation Network Company
TUS – Bureau of Technical Utility Services
V – Voltage



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