

## Chapter 2

# The Cost Approach to Pricing: The Direction of Cost

**Abstract** Two elements enter into the determination of the price of every component exchanged in the economy: the costs of producing, transporting, and delivering it, on the one hand, and its value to the buyer, on the other hand. Under price regulation, these two individual elements are the subject of highly developed formal processes and strictures, particularly as to costs. Chapters 2, 3, and 4 explore the economics of various aspects of the cost approach. Chapter 2 emphasizes one central principle—that prices tend to follow the direction of costs. To determine this direction, costs are examined from their fundamental role as either fixed or variable, and whether in combination they lead to decreasing, constant, or increasing per-unit costs. For capital-intensive industries, such as the energy utilities, the direction of unit costs is downward as plant is utilized more extensively with growth. Comparative scenarios are presented which analyze growth in its several stages, even or erratic, constant or interrupted, with resulting changes in the firm's prognosis.

## 2.1 Preface

Cost of service is the first of three basic approaches to utility pricing theory and practice. Under this approach, price determination is viewed from the supply side of the economic spectrum. The regulatory objective is that rates charged to customers will approximate the costs of rendering the service to these customers as closely as possible.

Cost analyses, consistent with standard accounting and economic analytical procedures, provide the foundation for the cost of service approach. In addition, these more or less standardized procedures are augmented and refined by the specialized tools and concepts peculiar to the energy utilities, which are explained in Chap. 11.

Henry Ford is credited with having introduced the concept of mass production into the American economy. If a product can be manufactured in quantity, Ford

reasoned, the cost of each item produced can be cut to a minimum. So, Ford created the assembly line. As autos emerged from the line in growing numbers, the direction of the cost per auto trended down (in non-inflated or constant dollars, of course). The downward trend in cost per auto made possible a corresponding downward direction in the price per auto.

We refer to this often-cited example of the Ford mass product assembly line to underscore a basic relationship between costs and prices in a competitive market: the direction of prices flows from the direction of costs.

In this chapter we treat the exploration of the direction of costs as an entry-pricing question. Others may see it as an intermediate or final issue. We do not argue which should come first, the chicken or the egg. We posit cost directionality at the beginning only because from our viewpoint such seems to best accommodate the logic of a cost approach to pricing. Whether first or last, an effective pricing policy cannot be blind to the direction of costs. Pricing, both for the present and the future, must comport with the reality of costs. Current prices must support current operations at current costs. Future prices must support future operations at future costs.

Transition from the present to the future is an inevitable fact of life. The transition from present costs and present prices, to future costs and future prices, must be faced head-on by the rate maker. The changeover may be smooth or rocky, orderly or disruptive, depending upon the degree and quality of the preparation for it. Today's pricing policy should anticipate the pricing requirements of tomorrow so that price changes will follow in a rational sequence. The type of analysis which follows can contribute to a smooth, orderly transition.

But there is another reason for an analysis aimed at foreseeing the direction of costs, and hence the direction of prices.

In many regulatory jurisdictions, utility prices carry an extra burden not imposed upon prices in other sectors of the economy. Utility prices are called upon to present a proper "signal" to buyers as to whether future prices will be higher or lower. Massive speculation or informed judgment? Whichever, it is to be hoped that buyers will not be misled.<sup>1</sup>

It should be obvious that if a price signal is to be valid, it must have a valid foundation. Prices move in tandem with costs, so a forecast of the direction of costs is key to any price signal which reasonably can serve to suggest how prices are likely to trend in the future.

We now turn to how costs and their direction may be analyzed to establish, among other objectives, an insight into the direction of prices.

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<sup>1</sup>The "signal" enigma introduces at least three uncertainties: what message is to be signaled? How should the message be couched in terms of present prices? And, will the message be recognized by the buyer, motivating the buyer to adjust buying habits to correspond to the signal?

## 2.2 Fixed and Variable Costs

The cost–price directional analysis segregates costs into two categories, fixed or overhead<sup>2</sup> and variable,<sup>3</sup> a classification referred to earlier in Chap. 1. *Fixed costs are those which remain constant (or relatively so) in total amount regardless of changes in the volume of business done.* Investment costs are fixed costs to the utility, because capital invested in plant and equipment does not change with sales fluctuations. Various other overhead costs are fixed also.

Fixed costs related to plant are also *sunk* costs. Once a capital investment has been made, the investment must be paid off regardless of whether the plant item is used or not, and regardless of the degree of utilization of the plant. The principal amount of the investment must be recovered, along with interest or equivalent on the unpaid balance. The alternatives, write-off of the unrecovered investment where the financial condition of the plant owner permits, or default on debt, where write-off is not feasible, are not viable considerations at the outset of instituting a capital investment.

Finally, fixed costs related to plant may be referred to as *embedded* costs, for the same reasons that they are sunk costs. They are embedded, i.e., included, in the utility's financial statements, and like other costs, are obligations which must be paid from revenues.

*Variable costs are those which vary in total amount with increases or decreases in the volume of business.* The cost of fuel (coal, oil, or natural gas) in a steam electric generating plant is a good example of a variable cost. As greater quantities of electricity are generated, more fuel is used, and fuel costs increase. Conversely, as generation drops off, fuel costs decrease. For natural gas companies buying gas for resale, the cost of purchasing gas at the wellhead is the principal variable cost.

It is important to understand the practical aspects of the relationship between fixed and variable costs. As production is increased with a given plant,<sup>4</sup> fixed costs,

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<sup>2</sup>Fixed or overhead costs are called “constant” costs by some writers. Martin Glaeser, an outstanding utility authority of an earlier era, recommends that they be called “capacity” costs. This is a useful concept inasmuch as most fixed costs are associated with the provision of capacity. Glaeser calls variable costs “out-of-pocket” costs. Glaeser, M.G., *Outlines of Public Utility Economics*, The Macmillan Company, New York, NY, 1931, Ch. XXVIII, p. 623.

<sup>3</sup>There are other ways of classifying costs for this purpose, depending upon the degree of refinement desired. An example of a three-way classification (given by Thompson, D.W. and Smith, W.R., *Public Utility Economics*, McGraw-Hill Book Company, Inc., New York, NY, 1941, Ch. 5) is (1) capital costs; (2) fixed operating costs; and (3) variable operating costs.

<sup>4</sup>The term *plant* is used in this chapter in a very broad sense to mean all or any part of the physical facilities, including land, equipment, machines, tools, buildings and grounds, etc., which are necessary to provide the utility service. Major additions to plant might mean, in the electric industry, an additional generating station, an important transmission line, or a large substation; in the natural gas industry, looping a pipeline main, a new compressor station, an additional city gate, storage, etc. Such additions may be made in any phase of the utility's operations (production, transmission, or distribution) or may, for balanced development, encompass all phases. Often the latter will be the case.

remaining constant in total, are borne by a larger number of units of output, and the amount of the total fixed costs which each unit must support is decreased. Variable costs, however, while changing in total, remain approximately equal for each unit of output. Thus, to use our previous electrical example, investment costs *per kilowatt-hour* will decline as production increases, but fuel costs *per kilowatt-hour* will not change significantly.

The distinction between fixed and variable costs is seldom clear-cut. There are a number of different circumstances which may change the usual characteristics of costs. Investment costs, ordinarily fixed, will increase significantly if major additions to plant are made to expand production and sales, or will decline if major plant items are retired from service. This illustrates that there is a long-run relationship between fixed costs and business volume, and that costs generally considered fixed will react to large changes in output. Conversely, many costs which ordinarily are variable may remain constant for short periods. It may be desirable, for example, to keep trained workers on the rolls during temporary slack periods rather than lose them and later incur the expense of training new employees. Also, some types of costs have mixed characteristics. To illustrate, even a part of the fuel costs of the electric generating plant, which as before mentioned are predominantly variable, may be fixed. This is due to the frequent necessity to burn a minimum amount of fuel to keep the plant in a standby status during periods when the burning of fuel would not otherwise be required. *It is thus apparent that costs may be classified as fixed or variable only on the basis of defined ranges of output and given periods of time.*

### 2.2.1 The “Readiness to Serve” Concept

An important part of utility rate theory has been developed out of the fixed–variable classification of costs. In addition to investment costs which already have been mentioned, utility fixed costs include such items as property taxes, insurance, non-operating depreciation, basic maintenance, salaries of officials, and wages of the minimum staff of employees. If the utility is to be in a position to render service when needed by its customers, it must incur these fixed expenses.

The utility plant, whether it be electric, gas, or other, may be used to capacity only part of the time. Nevertheless, adequate capacity to take care of maximum service requirements “on demand” of customers must be provided. Once the plant capacity is provided, the investment expenses associated therewith are constant in the sense of being unavoidable.<sup>5</sup> Similarly, other expenses are unavoidable and constant if service is to be rendered as required. Together, they comprise the utility’s fixed costs. These costs are all associated with the obligation of the utility to be in a

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<sup>5</sup>Within the limits of ranges of output and periods of time previously mentioned. Also, accounting treatment of investment costs may cause annual booked costs to vary as depreciation changes the spread between gross and net plant; return requirements may change, as may property taxes, etc. *But investment costs must be met in any event.*

position to render service when needed. They must be incurred if electricity is to be available at the flip of a switch, telephone service at the lift of a receiver, or gas at the turning on of a jet. For this reason utility fixed costs are often called “readiness to serve” costs.

### ***2.2.2 The “Use of Service (Product)” Concept***

If the utility’s fixed costs are incurred in order to put it in a position to render service whenever demanded by the customer, its variable costs arise as the result of the *amount* of service taken by the customer. Thus, these costs are classified as “use of service” costs.<sup>6</sup>

### ***2.2.3 Relative Proportion of Fixed and Variable Costs***

It is almost universally the case that in electric utilities the proportion of fixed to variable costs is high. This is true also for gas utilities, if the cost of gas at the wellhead is excluded. The proportions will vary not only between different types of utilities, but also between individual utilities of the same type.

## **2.3 Decreasing, Constant, and Increasing Costs Conditions**

From a bird’s-eye vantage point, cost conditions may be seen as falling characteristically into one of three types, each viewed in constant dollars.

*Conditions of decreasing costs* are those in which average costs per unit<sup>7</sup> decline as additional units are produced or sold. The usual utility combination of a high ratio of fixed to variable costs typically gives rise to decreasing costs conditions,<sup>8</sup>

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<sup>6</sup>“Use of service” costs are often expressed in the specific terminology of the utility under consideration. In the electric industry, “use of service” costs are called “energy” costs and in the gas industry, “commodity” costs.

<sup>7</sup>Average costs are the result of dividing the number of units produced into total costs (fixed and variable). In the electric utility, the most common unit is the kilowatt-hour; in gas, either the cubic foot or the therm.

<sup>8</sup>Historically, utilities have been seen as characteristically operating under decreasing cost conditions. It has been generally true that utility firms experience decreasing average unit costs as their output increases. If so, often this is due to one or more of the following: first, a longer term circumstance, it may be due to the fact that most utility firms have not yet reached optimum size, i.e., the point where further increases in size would result in higher costs of operation; second, a short-term condition, it may be because utility firms have unused capacity so that output may be increased without a proportionate increase in fixed costs; or, third, an intermediate situation, utilities may be able to expand major plant units at costs comparable to existing units.

and will always do so where no substantial additions to existing plant are required for expansion of output.<sup>9</sup>

Plant expansion may alter the degree of the decline in unit costs, or even change the downward direction of the cost trend. For this reason it is necessary to explore costs within the ranges of output which can be supplied by existing plant separately from costs incurred where major new plant must be installed.

*Conditions of constant costs* are those in which average costs per unit will remain stable as a whole as additional units are produced or sold. This condition requires that substantial plant additions can be made at the same costs as existing plant. However, while costs as a whole may remain stable, decreasing costs will occur as the utilization of the new plant improves. New major plant additions almost always are sized to provide for future expansion, so at inception there will be spare capacity. As this spare capacity is used, unit costs will decline.

*Conditions of increasing costs* are those under which average costs per unit increase as a whole as additional units are produced or sold. This condition results when the costs of significant plant additions are higher than for existing plant. However, as for constant costs, the decreasing cost phenomenon will take place as the new plant is brought from initial to full utilization.

Each of the three conditions is explored in the following pages.

## 2.4 Decreasing Costs

The condition of decreasing cost is illustrated from two perspectives, static and dynamic. The static assumption assumes rather unrealistically an unchanging, stable plant. The dynamic considers plant changes over time.

### 2.4.1 The Static Hypothesis

As a generalized—and over simplified—illustration of decreasing cost conditions, we examine the case of utility operations extending over a substantial period with no major additions to or retirements of plant capacity. To simplify the illustration, we treat only of an electric generating plant, without consideration of the transmission and distribution components of the electric system.

In lieu of a generating plant, other major electric or natural gas facilities could have been selected—an electric substation or transmission line, or a natural gas pressure booster station or pipeline. The only difference between these units and a generating plant is that the plant manufactures energy, while the other units only handle it, changing voltage or pressure or carrying it from one location to another.

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<sup>9</sup>Theoreticians may treat conditions of decreasing costs as always being applicable only in the short run. The important reason for putting a time limit on such conditions is that over a longer period major additions to plant may be necessary, and since such additions are in the future their costs are unknown or at least speculative. This is a good point, but is an unnecessary refinement for our discussion.

**Table 2.1** Illustration of the operation of fixed and variable costs (Static Plant)

Annual output in billions of kwh	Annual cost (\$ million)			Per kwh cost		
	Fixed cost	Variable cost	Total cost	Fixed cost	Variable cost	Total cost
4	600	40	640	15.0¢	1.0¢	16.0¢
6	600	60	660	10.0	1.0	11.0
8	600	80	680	7.5	1.0	8.5
10	600	100	700	6.0	1.0	7.0
12	600	120	720	5.0	1.0	6.0
14	600	140	740	4.3	1.0	5.3
16	600	160	760	3.7	1.0	4.7
18	600	180	780	3.3	1.0	4.3
20	600	200	800	3.0	1.0	4.0

System capacity: 20 billion kwh per year

Fixed costs: \$600 million per year

Variable costs: 1¢ per kwh

Generating plant utilization is stated as *output*, while utilization of the others is stated as *throughput*. This difference does not detract from the applicability of the generating plant to exemplify decreasing cost conditions in general. We have merely adopted the plant as a proxy for any major utility facility or appropriate group of facilities. We add that the proxy applies equally to like facilities of other capital-intensive industries, such as a steel mill or an automobile assembly plant.

The input assumptions for the generating plant are stated at the bottom of Table 2.1. The plant capacity of 20 billion kWh annually represents dependable output as required by the load shape, at point of consumption (sales), after allowance for losses, necessary reserves, down time for maintenance, etc.

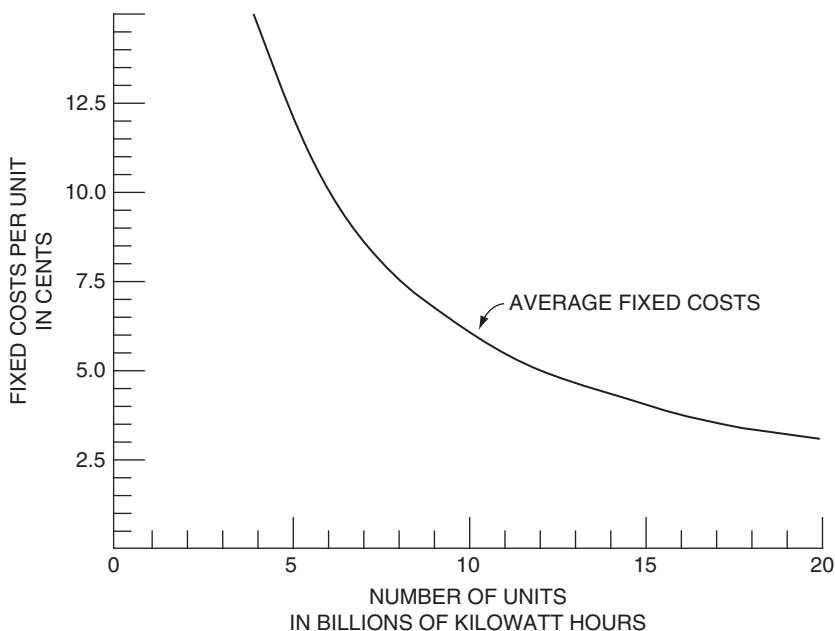
Table 2.1 illustrates that the fixed costs (in constant dollars) which must be borne by each kWh decline as additional units are produced. Fixed costs amount to 15 cents per kWh if only 4 billion kWh are sold. They decrease to 6 cents if 10 billion kWh are sold, further decreasing to 3 cents per kWh at capacity output of 20 billion kWh.

The trend of decreasing fixed costs per kWh as output expands is graphed in Fig. 2.1. Fixed costs, of course, are only a part of total costs. Variable costs of 1 cents per kWh are superimposed upon the curve of fixed costs in Fig. 2.2.<sup>10</sup>

<sup>10</sup>An example of an average variable cost of about 1 cent per kWh for a utility company with a mix of fuels is the 1993 experience of Kansas Gas and Electric Company. Its cost as reported in its 1993 Form 10-K was:

Weighted average cost of fuel, per million BTU

Nuclear	\$0.35
Coal	0.96
Gas	2.37
Oil	3.15



**Fig. 2.1** Average fixed costs under decreasing cost conditions (static plant)

Figures 2.1 and 2.2 show the decline in fixed and total *per-unit* costs as output expands. Total fixed costs remain the same regardless of the stage of production, and variable costs increase. As indicated in Table 2.1, combined fixed and variable costs rise from \$640 million at a low output to \$800 million at full output.<sup>11</sup>

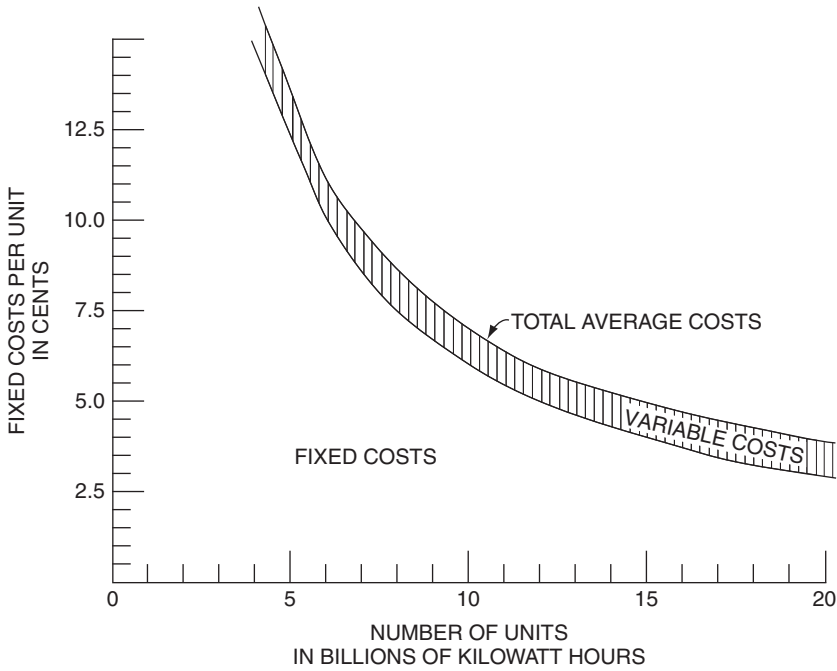
The foregoing illustrations are presented to hammer home the phenomenon of a decreasing *per-unit* cost situation which occurs as a major facility is brought from partial to full utilization. Essentially, a static situation is implied—a single very large plant progressing from minimal to full output. But utility operations are not static.

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Cost per kWh generated: 0.93 cents.

Many utility operations are most efficient at or near capacity or name-plate output. For this reason, variable costs will change per unit as well as in total for different amounts of production, frequently being lowest near the point of capacity output. When this is true, it reinforces the trend toward decreasing unit costs. Variable unit cost changes, however, are minor as compared with changes in fixed costs per unit and are accordingly disregarded in this illustration.

<sup>11</sup>The reader is requested to note, and put in the back of his mind for later reference until marginal cost pricing is discussed, that the marginal cost per unit for any expansion of output along all of the ranges of output illustrated in Figure 2.1 and Table 2.1, except beyond the last increment reaching to 20 billion kWh, is 1 cent. For example, output can be increased from 10 billion kWh to 18 billion kWh at an additional cost per unit – marginal cost – of 1 cent.



**Fig. 2.2** Average total costs under decreasing cost conditions (static plant)

### 2.4.2 The Dynamic Hypothesis

We now drop the static plant scenario in favor of a more realistic growth-over-time paradigm, hoping that it will be sufficiently *de rigueur* in spite of some continued simplifications.

Our treatment of fixed costs incorporates an important simplification. We show total fixed costs remaining stable (levelized) for each plant throughout the following illustrations. Normal costing practice for regulated utilities would be to reduce the investment—and therefore fixed costs—each year by the depreciation for that year. This practice in itself would cause declining unit cost trends there shown. Stable costs over a period follow the “home mortgage” principle for repayment of investment with interest.

A second important simplification is the substitution of “stages of production” for time periods. Thus, we may refer to outputs ranging from 1, 2, 3, . . . , 20, etc. as stages rather than as loads in any particular year. A stage may occur for less or more than a year. The stages do not forecast load growth. *The stages represent an annual output level with which is associated a given level of annual costs.* In this sense, a stage of production is equivalent to an annual output.

2.5 The Base System

As a foundation for exploring dynamic operations, past and future, we recast our prior illustration of fixed costs in a more realistic dimension. We substitute three plants for the single plant of Table 2.1, keeping output and investment costs (fixed costs) the same, as stated on Table 2.2:

Table 2.2 Base system plants		
Plant	Annual output capability (billions of kWh)	Annual fixed costs (\$ millions)
#1	4	140
#2	6	180
#3	10	280
Total	20	600

We refer to these three plants as the base system. Considering variable costs to be relatively constant per unit, we incorporate only fixed costs.

We assume that Plant #1 came online to supply the early, small magnitude loads, and remains online. Plant #2 was introduced when required to supply loads in excess of 4 billion kWh. It also remains online. Plant #3 became operative when the load exceeded 10 million.

Figure 2.3 diagrams sales volume in relation to additions to capacity. Neither the horizontal nor the vertical axis represents time periods. Load growth would not occur symmetrically. Figure 2.3 merely matches sales and capacity, regardless of the calendar.

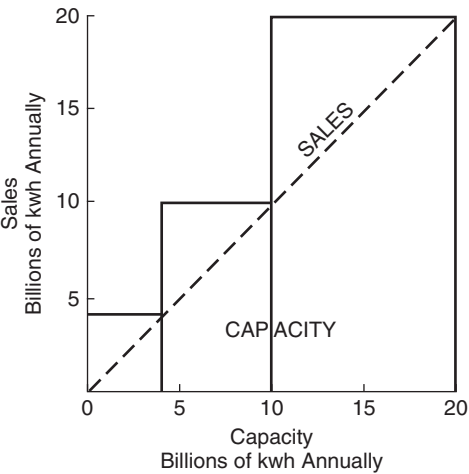


Fig. 2.3 Base system dependable capacity vs. output (sales)

**Table 2.3** Base three-plant generating system: fixed costs by plant

Annual plant output billions of kWh)	Annual fixed costs		Dependable energy capacity factor (%)
	Total annual fixed costs (\$ millions)	Costs per kWh (¢)	
Plant #1			
1	140	14.0	25
2		7.0	50
3		4.7	75
4	140	3.5	100
Plant #2			
1	180	18.0	17
2		9.0	33
3		6.0	50
4		4.5	67
5		3.6	83
6	180	3.0	100
Plant #3			
1	280	28.0	10
2		14.0	20
3		9.3	30
4		7.0	40
5		5.6	50
6		4.7	60
7		4.0	70
8		3.5	80
9		3.1	90
10	280	2.8	100

Table 2.3 tabulates fixed costs in total and per kWh individually for each plant of the base system. Unit fixed costs for the individual plants counterpart in miniature the declining costs shown in Fig. 2.1.

The right hand column in Table 2.3 introduces a new index to suit this and later illustrations, for which we have coined the term “dependable energy capacity factor.” As we use it, the term means *the ratio of the output delivered to customers (sales), to the dependable energy-serving capacity of the plant or system*, over a calendar period or stage of production. Such capability is less than name plate capacity, which must be greater to accommodate peaking requirements, losses, reserves, etc.<sup>12</sup> We turn to sales as the numerator because we state per-unit costs in terms of the amounts which must be recovered by customer prices.

<sup>12</sup>Changes in load shapes from one stage of production to another are not integrated into this factor, which, as used here, assumes a generally consistent load shape but without specifying a given sales load factor or factors.

**Table 2.4** Base three-plant generating system: fixed costs in total and per kWh

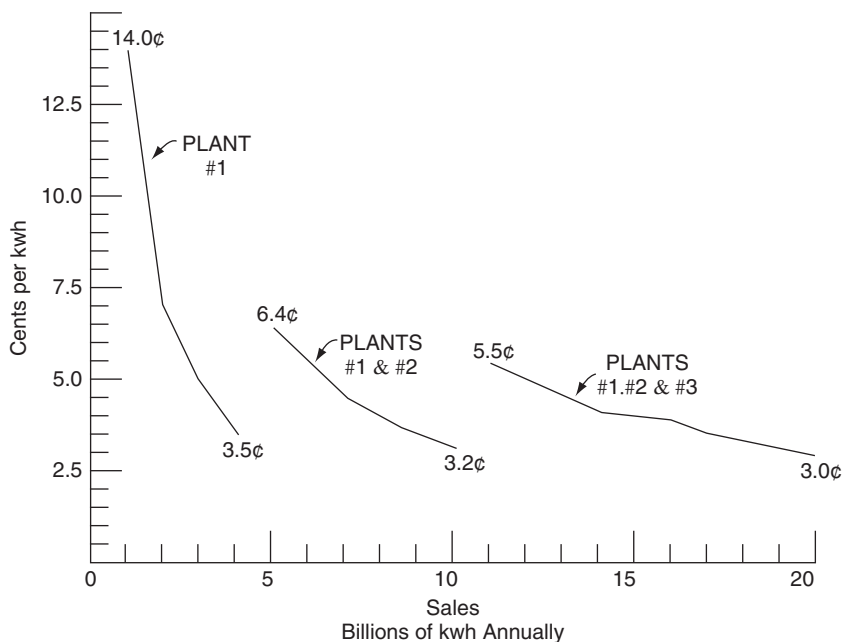
Sales (dependable output) (billion kWh)	Fixed costs (\$ millions)				System fixed costs per unit (¢)	Dependable energy capacity factor (%)
	Plant #1	Plant #2	Plant #3	System (combined)		
1	140			140	14.0	25
2					7.0	50
3					4.7	75
4	140			140	3.5	100
5	140	180		320	6.4	50
6					5.3	60
7					4.6	70
8					4.0	80
9					3.6	90
10	140	180		320	3.2	100
11	140	180	280	600	5.5	55
12					5.0	60
13					4.6	65
14					4.3	70
15					4.0	75
16					3.8	80
17					3.5	85
18					3.3	90
19					3.2	95
20	140	180	280	600	3.0	100

Now we can explain the fixed costs of the phased-in operation, with first one, then two, and finally all three plants online as stated in Table 2.4.

The dependable energy capacity factor is a consistent measure of the utilization of an integrated system. For example, Plant #1 reaches full utilization, a factor of 100%, at an output of 4 billion kWh. When Plant #2 is first added, the combined output is 5 billion kWh. The factor declines to 50%, since the 5 billion kWh output is only half of the new combined capability of 10 billion kWh.

Composited per-unit fixed costs for the base system are graphed in Fig. 2.4. Here we confront one of the more disagreeable facts of utility life—the *cost spikes* which are almost certain to occur when major new capacity comes in line. The fixed costs of Plant #1 have declined to 3.5 cents per kWh as it reached full operation. When Plant #2 is added, system average fixed costs jump to 6.4 cents per kWh (although they decline to 3.2 cents per kWh later as full production is reached). And when Plant #3 is added, they escalate from the prior average of 3.2 to 5.5 cents (but again declining with expanded production to 3.0 cents).

If the cost of spikes of the generating system of Fig. 2.4 were coincident in time of occurrence with cost spikes for other plant elements, a very difficult rate problem would be posed. If rates were to track costs precisely, they would be unacceptably erratic. However, such coincidence in time of occurrence seldom



**Fig. 2.4** Base system fixed costs per kilowatt-hour

happens. There tends to be the same diversity in the addition of facilities as there is in loads. Utility systems as a whole generally are so large that even the cost impact of a major facility addition is tempered if not absorbed in the overall body of costs.

Non-generating components of the electric system are a vast mix of diverse facilities which are at different stages of the cost curve. When intermingled in a company-wide cost of service, they tend to balance each other. Overall, the tendency in the entirety, in most cases, is declining unit costs in constant dollars.

## 2.6 Future Additions

The analyst seeking to determine the future magnitude and direction of costs as a guide to the future direction of prices will select some take-off point as being reasonably representative of the immediate past and current situation. For our purposes, we adopt as the beginning point the composite experience of the foregoing three-plant base system over the range of outputs from 11 to 20 billion kWh per year as indicated in Table 2.4.

To this base we add two new plants, Plants #4 and #5, under three different scenarios: a continuation of decreasing cost conditions; stable fixed costs, with the same per-unit investment for new plants as for the base system currently online (constant

**Table 2.5** Millions of dollars of annual fixed costs per one million kWh of annual output (in constant dollars)

The base system			
	Plant #1	\$35	
	Plant #2	\$30	
	Plant #3	\$28	

The alternative scenarios			
	Decreasing cost	Constant cost	Increasing cost
Plant 4	\$27	\$30	\$40
Plant 5	\$26	\$30	\$45

cost conditions); or higher fixed costs, with a higher per-unit investment for new plants than for currently operational plants (increasing cost conditions).

The dollars of investment to be assigned to each of these three possible scenarios will unavoidably be judgmental. For the present illustrative purposes they need be no more than that. For a study which is made to be the basis for pricing policy decisions, however, the judgment should rest upon thorough engineering-economic analyses of the costs of alternative energy supplies. (Whether simple judgment or informed judgment, the costs adopted will be speculative to a degree since there is no certainty as to the future.)

We tabulate above the illustrative fixed cost values selected for Plants # and #5. (Table 2.5) in millions of dollars of annual fixed costs per 1 billion kWh of annual output (in constant dollars).

**2.6.1 Decreasing Fixed-Cost Scenario**

This case rests upon an optimistic outlook. We have not yet reached the limits of the economies of scale. Our engineers have not exhausted their ingenuity to introduce refinements in technology which will result in better, more efficient, and less costly designs. (The writer acknowledges a bias in favor of this assumption, being incurably influenced by the technological advances of the past. But this bias is beside the point, since the judgment as to which of the three possible scenarios to adopt is not his but that of the utility and its regulators.)

The optimism of the case is modest. Plant #4 costs 10% less than the base system, and Plant #5, 13% less, but these plants cost only 4 and 7% less, respectively, than Plant #3 of that system.

Results are summarized in Table 2.7. Per-unit fixed costs at selected utilizations of capacity given in Table 2.6:

**Table 2.6** Comparative fixed costs at selected capacity factors: decreasing fixed costs

Dependable energy capacity factor (%)	Fixed costs per kWh (¢)		
	Base	Plants 1–4	Plants 1–5
80	3.8	3.6	3.5
90	3.3	3.2	3.1
100	3.0	2.9	2.8

**Table 2.7** Decreasing fixed-cost scenario

Annual sales (dependable output) (billion kWh)	Annual fixed costs (millions of constant dollars)				Fixed costs per kWh (¢)	Dependable energy capacity factor (%)
	Base system	Plant #4	Plant #5	Dec. cost system		
11	600			600	5.5	55
12					5.0	60
13					4.6	65
14					4.3	70
15					4.0	75
16					3.8	80
17					3.5	85
18					3.3	90
19					3.2	95
20	600			600	3.0	100
21	600	270		870	4.1	70
22					4.0	73
23					3.8	77
24					3.6	80
25					3.5	83
26					3.3	87
27					3.2	90
28					3.1	93
29					3.0	97
30	600	270		870	2.9	100
31	600	270	260	1,130	3.6	78
32					3.5	80
33					3.4	83
34					3.3	85
35					3.2	88
36					3.1	90
37					3.1	93
38					3.0	95
39					2.9	98
40	600	270	260	1,130	2.8	100

2.6.2 *Constant Fixed-Cost Scenario*

Constant cost is a valid scenario, although to an extent it begs the issue. Essentially it assumes, for example, that the higher costs of electric generation imposed by environmental measures will precisely be offset by design improvements. Or, in the alternative, the case may be taken to represent conservation steps requiring invested dollars which are equivalent to the dollars required for one or the other of the two new plants. (The writer thinks it unlikely that even the most draconian conservation program could be a substitute for both of the new plants.)

The level of investment assumed in this constant cost case is \$30 million per billion kWh of dependable output, the average for the base system.

Table 2.9 summarizes the results: per-unit fixed costs at the same selected capacity utilization factors given in Table 2.8:

2.6.3 *Increasing Fixed-Cost Scenario*

It is unfortunate that the future cannot be faced with undiluted optimism. Caution dictates that full consideration be given to a future in which increasing unit costs in constant dollars would materialize, a future which many see as likely.

For the electric industry, it certainly is possible that reliance may have to be placed on new nuclear generating units. It also is possible that these units will be more expensive because of environmental restraints, the still unresolved hazards of nuclear waste storage, the fear of locating such plants in proximity to population centers, etc. Conventional fuel plants also may be more expensive.

The costs of non-conventional electric generation are virtually unknown when considered as a primary reliable source for base-load power. Wind, solar, and cogeneration exist, but are still to be tested in the context of main-line electric system support. Will costs be high?

Conservation—i.e., reducing consumer demands—works, but only to dampen demand. When customer usage has been cut to the minimum as conservation runs its full course, new power supplies will be needed. Robust quantities of energy are essential to our economy as we know it, even assuming the maximum efficiency of use.

**Table 2.8** Comparative fixed costs at selected capacity factors: constant fixed costs

Dependable energy capacity factor	Fixed costs per kWh		
	Base	Plants 1–4	Plants 1–5
80%	3.8¢	3.8¢	3.8¢
90%	3.3¢	3.3¢	3.3¢
100%	3.0¢	3.0¢	3.0¢

Table 2.9 Constant fixed-cost scenario

Annual sales (dependable output) (billion kWh)	Annual fixed costs (millions of constant dollars)				Fixed costs per kWh (¢)	Dependable energy capacity factor (%)
	Base system	Plant #4	Plant #5	Constant cost system		
11	600			600	5.5	55
12					5.0	60
13					4.6	65
14					4.3	70
15					4.0	75
16					3.8	80
17					3.5	85
18					3.3	90
19					3.2	95
20	600			600	3.0	100
21	600	300		900	4.3	70
22					4.1	73
23					3.9	77
24					3.8	80
25					3.6	83
26					3.5	87
27					3.3	90
28					3.2	93
29					3.1	97
30	600	300		900	3.0	100
31	600	300	300	1,200	3.9	78
32					3.8	80
33					3.6	83
34					3.5	85
35					3.4	88
36					3.3	90
37					3.2	93
38					3.2	95
39					3.1	98
40	600	300	300	1,200	3.0	100

Moving from electric generation to transmission, it is possible that public policy would dictate that electric distribution lines (both primary and secondary) be relocated from overhead to underground to avoid sight pollution; possibly transmission lines might have to be relocated because of electromagnetic fields. Or it might be that gas transmission lines would be limited to less than economic size or allowable pressures, or that fears of line breaks would force the relocation of high capacity long distance mains away from urban areas. Decreasing unit costs in these several areas could be reversed. The pessimist can go on and on.

As in our prior scenarios, to illustrate increasing fixed costs, we add two new plants to the base system. We assume that Plant #4 has fixed costs of \$40 million annually for each 1 billion kWh of annual output. With the same dependable annual

capacity of 10 billion kWh, yearly fixed costs are \$400 million. These costs are 33 1/3% higher than the base system, and 43% higher than Plant#3 of that system.

For the second added plant, Plant #5, we assume even higher fixed costs, \$45 million for each 1 billion kWh of dependable capacity, or, with a 10 billion kWh annual output, \$450 million annually. The fixed costs of Plant #5 are 50% higher than the base system, and 61% higher than Plant #3.

This case is outlined on Table 2.11. At selected utilizations, per-unit fixed costs are given in Table 2.10:

**Table 2.10** Comparative fixed costs at selected capacity factors: increasing fixed costs

Dependable energy capacity factor (%)	Fixed costs per kWh (¢)		
	Base	Plants 1–4	Plants 1–5
80	3.8	4.2	4.5
90	3.3	3.7	4.0
100	3.0	3.3	3.6

Decreasing costs prevail as output for each plant addition advances from minimum to maximum.

## 2.7 The Small Base-Load Plant

To this point, only larger-scale generating plants (as representative of any major facility, electric or gas, of comparable cost) have been incorporated into the possibilities to be considered for the future. Smaller-scale plants now are also under consideration. In electric terms, smaller generating plants may either be base-load generators, substituting for larger plants, or peaking or firming-up plants, where only peaking capability is deficient. The present scenario is directed to the former. In gas terms, a new smaller pipeline or distributor transmission main can be installed initially rather than a larger main, to be paralleled later in the same fashion as an additional small electric plant may be added to augment the capability of an earlier small plant.

The present scenario assumes that two smaller plants will be substituted for each of the larger plants. In other words, the smaller plants will have a dependable energy capability of one-half of that of the larger plants, or 5 billion kWh annually. But at what cost?

Not being Solomon, we resort to the pragmatic. Smaller new plants are not quite as efficient as larger plants, perhaps. And if larger new plants may be more expensive than earlier larger plants (our increasing cost scenario), then smaller new plants may be more expensive also, perhaps. We don't know. So, solely for illustration, we adopt the Plant #4 costs (under the increasing cost scenario) of \$40 million per 1 billion kWh for the first two substitute plants, Plants #4-A and #4-B; and we adopt Plant #5

**Table 2.11** Increasing fixed-cost scenario

Annual sales (dependable output) (billion kWh)	Annual fixed costs (millions of constant dollars)				Fixed costs per kWh (¢)	Dependable energy capacity factor (%)
	Base system	Plant #4	Plant #5	Inc. cost system		
11	600			600	5.5	55
12					5.0	60
13					4.6	65
14					4.3	70
15					4.0	75
16					3.8	80
17					3.5	85
18					3.3	90
19					3.2	95
20	600			600	3.0	100
21	600	400		1,000	4.8	70
22					4.5	73
23					4.3	77
24					4.2	80
25					4.0	83
26					3.8	87
27					3.7	90
28					3.6	93
29					3.4	97
30	600	400		1,000	3.3	100
31	600	400	450	1,450	4.7	78
32					4.5	80
33					4.4	83
34					4.3	85
35					4.1	88
36					4.0	90
37					3.9	93
38					3.8	95
39					3.7	98
40	600	400	450	1,450	3.6	100

costs of \$45 million per 1 billion kWh for the second two substitute plants, Plants #5-A and #5-B. We suggest higher costs for the second two smaller plants for the same reason as we adopted higher cost for Plant #5 than for Plant #4, viz., that while the later plant might have the same or even better technology that the earlier plant, locational or other factors could be more difficult.

Costs for this configuration are calculated in Table 2.12. They may be compared with the costs for Table 2.11, since generation costs per billion kWh of output are the same on both tables. The cost spikes for the small plant system are much less drastic than for the large plant system, as would be expected. For example, as output progresses from 20 to 21 billion kWh, the spike for the small plant system is from 3.0 to 3.8 cents, a spread of .8 cents, while for the larger plant system it is from

**Table 2.12** The small base-load plant (increasing fixed costs)

Annual sales (dependable output) (billion kWh)	Annual fixed costs (millions of constant dollars)				Fixed costs per kWh (¢)	Dependable energy capacity factor (%)
	Base system	Plant #4-A & #4-B	Plant #5-A & #5-B	Small plant system		
20	600			600	3.0	100
21		200		800	3.8	84
22					3.6	88
23					3.5	92
24					3.3	96
25		200		800	3.2	100
26		400		1,000	3.8	87
27					3.7	90
28					3.6	93
29					3.4	97
30				1,000	3.3	100
31			225	1,225	4.0	89
32					3.8	91
33					3.7	94
34					3.6	97
35			225	1,225	3.5	100
36			450	1,450	4.0	90
37					3.9	93
38					3.8	95
39					3.7	98
40	600	400	450	1,450	3.6	100

3.0 to 4.8 cents, a spread of 1.8 cents. Of course, there are twice as many spikes in Table 2.12 as in Table 2.11.

Table 2.13 compares the unit costs of the two systems. Unit costs are less for outputs from 21 to 25 billion kWh, and for outputs from 31 to 35 billion kWh, the outputs at which Plants #4-A and #5-A are substitutes for the initial stages of utilization of larger Plants 4 and 5.

Aggregate savings in costs are calculated from the unit cost savings. These also are shown in Table 2.13. (For example, at an output of 21 billion kWh, a unit cost saving of 1.0 cents per kWh results in a total saving of \$210 million.) The total of these savings differs from the expected total due to rounding of the unit costs in Tables 2.11 and 2.12.

Expected savings are calculated from the differences in the fixed-cost burdens in the corresponding output stages as between Plants #4-A and #5-A, and Plants 4 and 5.

**Table 2.13** Comparison of costs of large and small plant systems (Tables 2.11 and 2.12)

Annual output (billions of kWh)	Fixed costs per kWh (¢)		Reduction in costs due to smaller plants	
	Large plant system	Small plant system	Per kWh (¢)	Total (\$ millions)
21	4.8	3.8	1.0	210
22	4.5	3.6	0.9	198
23	4.3	3.5	0.8	184
24	4.2	3.3	0.9	216
25	4.0	3.2	0.8	200
Subtotal				1,008 <sup>a</sup>
26	3.8	3.8	—	—
27	3.7	3.7	—	—
28	3.6	3.6	—	—
29	3.4	3.4	—	—
30	3.3	3.3	—	—
31	4.7	4.0	0.7	217
32	4.5	3.8	0.7	224
33	4.4	3.7	0.7	231
34	4.3	3.6	0.7	238
35	4.1	3.5	0.6	210
Subtotal				1,120 <sup>b</sup>
36	4.0	4.0	—	—
37	3.9	3.9	—	—
38	3.8	3.8	—	—
39	3.7	3.7	—	—
40	3.6	3.6	—	—
Total				\$2,128 <sup>c</sup>

<sup>a</sup>Differs from \$1.0 billion due to rounding of per kWh costs.

<sup>b</sup>Differs from \$1.125 billion due to rounding of per kWh costs.

<sup>c</sup>Differs from \$2.125 billion for reasons stated above.

This calculation is given in Table 2.14:

With due regard to the heroic assumptions which have been the basis of this scenario, it would seem that there is little doubt that equivalent smaller plants will be cheaper than larger plants, provided that they can be constructed at about the same cost per unit of output. Of course, that is an essential and perhaps elusive proviso. Over many years of history, larger capacity plant elements, both electric and gas, have been cheaper than smaller capacity units.

Distributed generation: The “small” plants represented by this scenario are not really small except in relation to the large plants for which they are substitutes.

**Table 2.14** Cost differences between large and small plants

Outputs	Millions of dollars		
	Fixed-cost burden		Reduction in burden
	Large plants	Small plants	
21	1,000	800	200
22	1,000	800	200
23	1,000	800	200
24	1,000	800	200
25	1,000	800	200
			1,000
31	1,450	1,225	225
32	1,450	1,225	225
33	1,450	1,225	225
34	1,450	1,225	225
35	1,450	1,225	225
			1,125
	Total reduction (savings)		2,125

Under the heading, “Thinking Small: Onsite Power Generation May Soon Be Big,” Keith G. Davidson and Gerald W. Braun<sup>13</sup> suggest much smaller plants.

They write (1993),

Eventually, smaller and cleaner generation units located near major load centers could begin to supplement power from central plants.

The technologies necessary to this transition are emerging in the form of “distributed generation.” These technologies typically produce power on a relatively small scale (less than 50 MW per unit) and can be cited in congested urban areas as well as near remote customers. This allows utilities to meet new demand for electricity without building central generating stations or upgrading the power delivery system—in other words, at lower costs.<sup>14</sup>

## 2.8 The Peaking or Firming-Up Plant

Both electric and gas utilities may find that they have ample supplies of energy, but are deficient in peaking capability. In this situation it may be the best course to add a peaking resource rather than the usual balanced peak-energy resource. For the

<sup>13</sup>Davidson is director of power generation and transportation systems, Gas Research Institute, and Braun is director of advanced energy systems research, Pacific Gas and Electric Company. Davidson, K.G. and Braun, G.W., “Thinking Small: On site Power Generation May Soon Be Big,” *Public Utilities Fortnightly*, July 1, 1993.

<sup>14</sup>In 1967, in a report prepared for the Bonneville Power Administration, the writer suggested the use of gas “in relatively small (20,000 kW to 50,000 kW each) gas turbine plants at the perimeters of electric transmission lines,” for system reliability, peak shaving, supplementing hydro storage, or system reserve. Conkling, Inc., “The Potential for the Natural Gas Industry in the Pacific Northwest,” US Dept. of the Interior, Bonneville Power Administration, 1967.

electric utility, this might mean adding a peaking generating plant; for the gas utility, it might mean adding storage capacity, doubling up on mains from its city gate to its distribution system, adding compression, or similar measures. (In the case of either utility it might mean the purchase of peaking from an outside source, an alternative we do not specifically consider in this scenario. Where that alternative exists, the utility will follow the least-cost route.)

A peaking deficiency also may arise because the utility is forced to sell energy on a non-firm basis since it does not have the capacity to guarantee delivery to customers during peak periods. Or, a version of the same, the utility may have the opportunity to buy non-firm energy which it could resell as firm energy if it had the capability to augment its non-firm energy when necessary.

For reasons such as the above, utilities may find it desirable to add special-purpose facilities. The construction of a model to fit such an uncertain array of circumstances is far from simple, and our attempt is far from perfect.

Continuing with electric operations as a base, we select for illustration a peaking generating plant to firm up an interruptible supply. To do this, we must put aside our assumption of prior scenarios that the capacity provided, while stated solely in energy terms, is capable of serving both the peak and energy requirements of the load as it exists. In other words, until this scenario we have assumed that the energy capability is delivered so as to fit the system load shape. This had the virtue of avoiding the complexity of distinguishing capacity as being firm or non-firm, or based upon assumptions as to sales load factors, diversity factors, etc. For the present case we must differentiate between firm and non-firm outputs, and hence at the relative values of firm and non-firm sales. We must again resort to heroically simplistic assumptions.

Referring back to Table 2.4 for the base system at outputs of from 11 to 20 billion kWh per year (the same beginning point as for our main case scenarios of Tables 2.7, 2.9, and 2.11), it will be recalled that the system was assumed to be able to produce up to 20 billion kWh annually so as to match the utility's load shape. With no change in the total market, we now assume that the system is able to produce only 15 billion kWh with sufficient peaking to serve maximum demands. The system can still generate the full 20 billion kWh (i.e., its energy capability has not been reduced), but it is short on peaking to be able to deliver the remaining 5 billion kWh as firm power. This results in the following output configuration given in Table 2.15.

Since interruptible energy can be sold only at a lower price than firm energy, we must assume a price for interruptible. For illustrative purposes, we assume 1.5 cents per kWh after covering variable costs.

The dilution of the output from all firm to part firm-part interruptible, means that the firm per kWh revenue requirement to satisfy fixed costs (which remain unchanged in total at \$600 million per year), will be increased for outputs above 15 billion kWh. The relevant firm service revenue requirements, with and without dilution, are given in Table 2.16:

The dilution has raised the firm service revenue requirement, for 16 billion kWh annually, from 3.8 cents per kWh to 3.9 cents, an increase of 0.1 cents per firm kWh;

**Table 2.15** Annual sales capability with and without interruptible

Total market	Firm	Interruptible
11	11	—
12	12	—
13	13	—
14	14	—
15	15	—
Total market	Firm	Interruptible
16	15	1
17	15	2
18	15	3
19	15	4
20	15	5

**Table 2.16** Comparative results of firm and split outputs

Annual output (billion kWh)	Annual fixed costs (\$ millions)	All firm (¢/kWh) <sup>a</sup>	Split output		
			Int. rev. (\$ millions)	Residual fixed costs	Firm rev. reg. (¢/kWh)
16	600	3.8	15	585	3.9
17	600	3.5	30	570	3.8
18	600	3.3	45	555	3.7
19	600	3.2	60	540	3.6
20	600	3.0	75	525	3.5

<sup>a</sup>Per Table 2.3.

at the 20 billion kWh stage of production, an increase of 0.5 cents per firm kWh, from 3.0 cents per kWh to 3.5 cents. Any steps which would reduce these increases to firm customers would be of benefit to these customers.

One route would be to purchase firming-up capacity (i.e., buying peaking without energy, probably through an energy exchange). If such capacity could be purchased so that the revenue requirement per firm kWh (the right hand column of the preceding table) would be reduced, the transaction would be advantageous to firm customers. An energy exchange would reduce the volumes available for interruptible customers. The reduction would depend upon the terms of the exchange, which might range from one-to-one to a multiple-to-one basis.

A more complicated route would be to add on-system peaking capacity. Since a generating plant cannot be operated without producing kilowatt-hours, such a plant would add energy as well as peaking. However, it would not be necessary that the on-system peaking plant be capable of producing the full energy output of the basic

**Table 2.17** Output and costs with peaking plant

Output capability (billion kWh) Peaking			Sales (billion kWh)		Annual costs (\$ millions)			
Base	Peaking	Total	Firm	Int.	Total	Int. Revenue	Balance for firm	Rev req. per kWh for firm (¢)
20	2.5	22.5	16	6.5	712.5	97.5	615.0	3.8
I	I	I	17	5.5	I	82.5	630.0	3.7
I	I	I	18	4.5	I	67.5	645.0	3.6
I	I	I	19	3.5	I	52.5	660.0	3.5
20	2.5	22.5	20	2.5	712.5	37.5	675.0	3.4

systems, since that system can produce the full energy requirement, being deficient only in peaking.

Since we have not specified any particular load shape for the basic system (and do not wish to add a further complexity by doing so at this juncture), we will assume that the peaking plant would generate one-half of the end-period volume to be firmed up, one-half of 5 billion kWh or  $2\frac{1}{2}$  billion, and that the fixed cost of such output is \$45 million per billion kWh or \$112.5 million per year. (This is the highest cost invoked in the preceding increasing cost scenario.) We now assume that the market is large enough to absorb the full capability of the combined plants (a change from the assumption that the market is limited to the 16–20 range).

With these assumptions, output, fixed costs, and the fixed-revenue requirement for firm sales are Table 2.17:

Given the assumptions (heroic, indeed) for each route, the results compare as in Table 2.18:

We do not specifically posit a case covering the opposite situation, namely where a utility has ample peaking capability but is energy deficient. In such a case the utility may attempt to exchange its surplus peaking for energy. Or it may advance the coming online of its next general purpose plant, which would provide the needed additional energy at least over the initial stages of production of that plant. In this event, it would have an early-on superabundance of peaking available for sale.

**Table 2.18** Fixed cost revenue requirement for firm service with peaking

Split output without peaking (¢)	Purchase of peaking with energy exchange	Addition of on-system peaking
3.9	Less than 3.9¢	3.8¢
3.8	Less than 3.8¢	3.7¢
3.7	Less than 3.7¢	3.6¢
3.6	Less than 3.6¢	3.5¢
3.5	Less than 3.5¢	3.4¢

## 2.9 Power Purchases by Electric Utilities from Non-utility Sources, Bypass, and Discounts

Unless most prognosticators of the future of the electric industry are wrong, the tide is running strongly in favor of purchases by utilities of an appreciable part of their power requirements from non-utility sources.<sup>15</sup>

Part and parcel of this trend, and perhaps the casual factor, is the growing threat of “retail wheeling” or “open access,” whereby an electric utility would be required to make available its transmission and distribution facilities to carry power from a non-utility generator to an end-user customer. This would enable larger industrial customers to bypass the utility’s generation by buying their power supply directly from independent power producers (now EWGs, or exempt wholesale generators) or cogenerators (or marketers, brokers, or other sources) to obtain a cheaper price than the utility can offer. The California PUC formally proposed retail wheeling in an April 20, 1994 “Restructuring” order.<sup>16</sup>

This scenario may be of help in sorting out the fixed-cost elements which may be considered in making comparative evaluations of power purchases, on the one hand, and bypass, on the other hand. Table 2.7 is the foundation for each of these evaluations. Wheeling is assumed.

### 2.9.1 *Purchase by a Utility*

Table 2.7 covers a utility’s base system plus Plants #4 and #5, the latter added under decreasing cost conditions.

At somewhere in the mid-range of outputs with Plant #4 online, the utility must consider the addition of Plant #5 or some other alternative to accommodate future load growth. As Plant #4 approaches full production, its fixed costs will decline to 2.9 cents per kWh. With Plant #5, the cost spike will escalate costs to 3.6 cents per kWh. Thereafter, unit costs decline over nine stages of production to a low of 2.8 cents.

Assumption: An Independent Power Producer (IPP) plans to construct a plant with a 5 billion kWh dependable energy capability. This plant can produce each billion kWh annually at a fixed cost of \$260 million per billion kWh. (The same cost as assumed in Table 2.7 for Plant #5)

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<sup>15</sup>In fact, the Division of Ratepayer Advocates of the California PUC, in its “Comments” of June 8, 1994 on the Commission’s April 20, 1994 OIR and OII, R.94-04-031 and I.94-04-032, expresses a “preference that utilities ultimately be completely out of the generation business . . . [when there is] a healthy wholesale generation market that can provide for all the utility’s generation and reliability needs.” California PUC, Division of Ratepayer Advocates, “Comments” on the Commission’s April 20, 1994 Restructuring Order, June 8, 1994.

<sup>16</sup>“Wholesale wheeling” or “transmission access” is already required by the Energy Policy Act of 1992. FERC can require a utility to transmit power from an EWG to a purchasing utility (a wholesale customer of the EWG). But “retail wheeling,” to an end-user customer, is still to be mandated. Public Utilities Commission of the State of California, Order of April 20, 1994, op. cit.

The IPP sees this fixed-cost picture as in Table 2.19:

**Table 2.19** Range of competitive costs

Annual output (billion kWh)	Annual cost (\$ millions)	Fixed cost per kWh (¢)	
1	130	13.0	
2	I	6.5	(Non-competitive)
3	I	4.3	
3.5	I	3.7	(Possible)
4.0	I	3.3	(Competitive)
4.5	I	2.9	(Range)
5.0	130	2.6	

Clearly, the IPP cannot be competitive unless it can sell the bulk of its capability. After gauging the market by contacting prospective industrial buyers, the IPP concludes that it can sell 2.5 billion kWh annually to industry, and reach a total of 4.5 billion kWh annually if the utility will buy 2 billion kWh each year. The IPP offers a price which includes a fixed-cost component of 2.9 cents per kWh.<sup>17</sup> This is the same cost as that shown for the utility when Plant #4 reaches full utilization (output of 30 billion kWh), but less than the cost of 3.6 cents per kWh when Plant #5 first comes online.

Should the utility take the offer?

### ***2.9.2 Construction by the Utility of Its Own Plant***

Presumably the utility could build the same plant at the same cost as the IPP (we see no reason why it couldn't). If it did, the following would be substituted for the 31–32 billion kWh outputs of Table 2.7 (Table 2.20). (These are the initial outputs with large-scale Plant #5 online, reflected in Table 2.7.)

### ***2.9.3 Purchase of IPP Power***

If the utility accepted the IPP offer of 2 billion kWh annually at a price of 2.9 cents per kWh for fixed costs (with a requirement to take-or-pay) it could substitute a \$58 million per year cost increment for a \$130 million increment, with the results in Table 2.21.

Under the above assumptions, the savings in fixed costs of \$72 million annually, a total of \$144 million over 2 years with the power purchase, would seem clearly to outweigh the excess capability for exchange or other disposition available with the company-owned plant.

<sup>17</sup> It also offers system control and delivery arrangements satisfactory to the utility (deliveries to fit the utility's load shape, an appropriate share of reactive, scheduling, etc.).

**Table 2.20** Utility-owned new plant

Output <sup>a</sup> (billion kWh)	Annual fixed costs (\$ millions)			Fixed costs per kWh <sup>b</sup> (¢)
	Base plus Plant #4	New small plant	Total	
31	870	130	1,000	3.23
32	870	130	1,000	3.13

<sup>a</sup>In addition, under Table 2.4's assumption of the utility's total load, the utility would have excess capability, declining from 4 to 1 billion kWh annually during the first four stages of production, which could be used for exchange, etc. Its resources would be in balance with its load at the fifth stage, 35 billion kWh.

<sup>b</sup>To hundredths of a cent.

**Table 2.21** Purchase of IPP power

Output (billion kWh)	Annual fixed costs (\$ millions)			Fixed costs per kWh <sup>a</sup> (¢)
	Base plus Plant #4	Purchase (take-or-pay)	Total	
31 <sup>b</sup>	870	58	928	2.99
32	870	58	928	2.90

<sup>a</sup>To hundredths of a cent.

<sup>b</sup>In addition, the utility would have 1 billion kWh available for exchange, etc., at this stage of production.

**Table 2.22** Comparative costs of generation alternatives

Output (billion kWh)	System average fixed costs per kWh (¢)		
	With large Plant #5 <sup>a</sup>	With utility—owned small plant	With purchase from IPP
31	3.65	3.23	2.99
32	3.53	3.13	2.90

<sup>a</sup>Per Table 2.4, to hundredths of a cent.

On a system-wide per kWh basis, unit costs would compare as in Table 2.22:

Decision: Other factors being equal, the utility would decide to postpone large-scale Plant #5, and would forego (or postpone) construction of its own small plant in favor of accepting the IPP offer of 2 billion kWh. It would foresee that additional capacity would be needed for the 33 billion kWh stage of production.

The utility would have no difficulty in accepting a long term take-or-pay contract with the IPP, since the fixed costs of that contract are lower-cost substitutes for the higher fixed costs which it would incur with the alternatives considered.

Comment: The above scenario illustrates the magnitude of the fixed-cost savings which are possible if the output of a plant operating at full utilization can be substituted for the output of a plant of equivalent cost operating at only partial utilization. (Recall the prior related scenario dealing with the small base-load plant, where output utilization was dependent upon load growth.)

It is easy to overstate the significance of these results in terms of long-range public policy. The most cogent question is, why in the world would a generating plant (or other major electric or natural gas facility) be operated at a poor capacity factor? The answer is, because utility facilities are built to satisfy load growth. Larger capacity facilities generally are cheaper per unit of capacity than smaller ones. They can be sized larger with economic benefit. A parallel pragmatic reason is that it is not efficient to size today's capacity solely to serve only today's loads. Capacity for tomorrow should be built in. Beyond generating stations, with their associated issues of sitting and outgoing transformation and transmission, good examples of why allowance for growth should be built into utility capacity, rather than added incrementally, are: an electric transmission line crossing occupied or environmentally sacred terrain, or through a corridor restricted in size; a natural gas main running under public streets; or even the electric service drop or the gas service main supplying individual customers. The public convenience requires that disrupting construction activity be kept to a minimum.

It could be that super-accurate advance planning of electric requirements over a broad area, perhaps via a super-pool, could integrate requirements with supply so as to attain a full or near full plant utilization when new plants come online. To some extent this has occurred. But whether the process can be perfected, if tried, remains to be seen.

### ***2.9.4 Bypass of the Utility***

The situation just reviewed is one where an IPP offer is of advantage to a utility. This may be a unique situation. What is not unique is the threat of bypass of the utility; i.e., loss of load by the utility due to large customers switching from the utility to an IPP, because IPP offers a lower price.

The IPP's do not have the utility's obligation to have capacity ready to satisfy demands as they occur. They attempt to garner a market for the whole of their planned output. They can do this if they are allowed to capture large users previously served by the utility (or perhaps groups of smaller users buying collectively), as they would be under retail wheeling.

The prior illustration assumed that the IPP was able to attract industrial customers requiring an output of 2.5 billion kWh per year, selling another two billion to a utility. Here we look at a different utility, the one who previously had served some of the lost industrial customers. We assumed that this present utility loses 2 billion kWh of annual load just as it is beginning its 34 billion kWh stage of production, at which stage the fixed-cost component in its rates is 3.324 cents per kWh. The

**Table 2.23** Results of bypass opportunities

Output (billion kWh)	Fixed costs Per kWh	Output (billion kWh)	Fixed costs Per kWh	Increase in fixed costs for remaining load	
				Per kWh	Total
31	3.645¢	31	3.645¢	—	—
32	3.531	32	3.531	—	—
33	3.424	33	3.424	—	—
34	3.324	32	3.531	0.207¢	\$66.2 million
35	3.229	33	3.424	0.195	\$64.4 million
36	3.139	34	3.324	0.185	\$62.9 million
//		//			
40	2.825	38	2.974	0.149	\$56.6 million

IPP offers a fixed cost of 2.9 cents per kWh, a saving of 15% for the buyer. For the moment we assume that the utility is not permitted to match the IPP's lower fixed-cost component.

Before the loss of load, unit costs (to fractions of a cent) for the Plant #5 stages of production are as stated in the first two columns. Revised unit costs, reflecting the loss of load are stated in the next two columns (Table 2.23).

The boxed area highlights the immediate impact of the bypass. The increase in fixed costs (representing lost revenue) which would have been absorbed by sales to the bypasser(s), but which now must be picked-up by the remaining customers, are indicated in the two right hand columns. These total \$131 million over the initial 2 years of the bypass. The impact per stage of production declines somewhat as system output approaches full system utilization due to the decline in fixed costs per-unit with increased outputs.

There is always, of course, a ray of sunshine even in a bad scenario. Here the sunshine is that the necessity for new generation capacity is delayed by the bypass for the time equivalent of two stages of production. Further, it seems reasonable to conclude that there is a limit to the utility loads which can be bypassed. When this limit is reached, plants (even smaller ones) will not be fully loaded at inception. Thus, the chain of high to low fixed costs per kWh over a range of outputs as we have reviewed in the earlier scenarios again comes into play.

The public policy issue: acknowledging that many economists contend to the contrary, nonetheless value judgments do enter into economics. The public policy issue here is, is the bargain gained by the large industrial bypasser(s) sufficient to override the resulting higher costs to the remaining body of the utility's customers? More narrowly, should bypass be encouraged (or even permitted) as an appropriate public policy, so as to lower rates to bulk users?

The essence of this public policy issue was raised early on by Frank Taussig, assistant commissioner of the Oregon PUC, in testimony before the Oregon Energy Facility Sitting Council (March 15, 1984).

For sake of example, let us assume that some industry is contemplating a 100 mw cogeneration source. From the industry's point of view, the cost of cogenerated power may be 4¢/kWh after the value of steam is accounted for. (For instance, the full cost may be 6.5¢/kWh, but the value of the steam may be 2.5¢/kWh.) If the serving utility has a price of 4.5¢/kWh, the industry saves 0.5¢/kWh, which works out to a benefit to the industry of \$3,504,000 per year (assuming an 80 percent capacity factor). This certainly looks attractive to the paper mill.

However, the serving utility has lost sales equal to the 100 mw generated by the paper mill. In the short run, since the utility has already put into place sufficient generating capacity to serve the paper mill, the utility has running costs (variable costs) of only 1.5¢/kWh to 2.0¢/kWh. Even at 2.0¢/kWh the utility would have made a margin of 2.5¢/kWh on those sales, and not making those sales therefore means that \$17,520,000 of margin is lost. This lost margin, which represents primarily the fixed costs of generating capacity already installed by the utility, must be picked up by other customers of the utility.

Thus, although the paper mill comes out ahead by \$3,504,000, the rest of Oregon will suffer to the tune of \$17,520,000. This is a reflection of the fact that we currently have a surplus of generating capacity. So long as we have a surplus, it cannot be economically correct to add more capacity.

### ***2.9.5 An Alternative to Bypass: A Discounted Price***

Just above we examined the impact of a loss of load of 2 billion kWh annually due to bypass, under the assumption that the utility was not permitted to match (or did not choose to match) the fixed-cost component of 2.9 cents per kWh offered by the IPP. Now, we reverse this assumption. The utility meets the IPP's competitive offer by discounting its component from 3.324 cents per kWh to 2.9 cents.

Table 2.24 summarizes the results. Part A shows that at the reduced component, the sales which otherwise would have been lost, contribute to \$58 million annually to fixed costs, bringing down the total fixed costs to be borne by core customers from \$1.130 billion annually to \$1.072 billion.

Part B shows that the \$58 million revenue at the discounted price component reduces the \$66.2–\$56.6 million loss which a bypass would have engendered to no greater than an \$8.5 million loss—and no less than a \$1.4 million gain, over the seven 34–40 billion kWh stages of production. There is a net gain in the last two stages of production because the 2.9 cents per kWh fixed-cost component paid by the industrial customer(s) is higher than the component which otherwise would have been incorporated in the rates.

The public policy issue: If the foregoing exercise dealing with competitive pricing to avoid bypass even remotely mirrors reality there would seem to be little question that the utility should be permitted to offer a competitive price to a potential bypasser. But does a discounted (competitive) price, offered only to customers who are in a position to bypass, constitute unjust or unreasonable discrimination?

This is not an easy question. (The writer says this as one who for many years has wrestled with “discriminatory—yes?” or “discriminatory—no?” On one side is the catechism precept, “Everyone must be treated equally;” on the other side is the market dogma, “Prices must be competitive.” Like east and west, the twain do not mesh readily.)

**Table 2.24** A discounted price to industrial customer(s) to prevent bypass

Part A: Fixed costs borne by core customers with discounted price to retain sale					
Output (billion kWh)			Fixed costs (millions of dollars)		
Total	Disc. sales	Core sales	Table 2.7 total (\$)	Less: disc. sales	Balance for core (\$)
34	2	32	1,130	58	1,072
35	2	33			
36	2	34			
37	2	35			
38	2	36			
39	2	37			
40	2	38	1,130	58	1,072
Part B: Loss/gain due to discounted price to retain sale					
Millions of dollars					
		2 billion kWh bypass rev. loss (\$)	Discounted rev.	Net loss/gain with discounted rates	
Output	Per kWh (¢)		Gain (\$)	Net loss (\$)	Net gain (\$)
34	3.324	66.2	58.0	8.2	
35	3.229	64.4		6.4	
36	3.139	62.9		4.9	
37	3.054	61.3		3.3	
38	2.974	59.4		1.4	
39	2.897	58.1			0.1
40	2.825	56.6	58.0		1.4

The issue of discrimination, however, rests upon the notion that the basic rates are “just and reasonable.” Presumably they are so. But, as discussed in Chap. 3, rates are developed through a series of allocations of joint costs, none of which can be proved or disproved except judgmentally. Perhaps new allocations, oriented more toward the competitiveness of the final results, would dispose of the discrimination issue. (See Chap. 5, The Value Approach to Pricing.)

A secondary policy issue is whether lost revenue resulting from a discounted price should be made up through higher core rates, or shared by ratepayers and stockholders, or fall entirely upon stockholders.

**2.9.6 Arrested or Contracted Output**

The prior scenarios presuppose growth—in demand and hence of output—although the rate of growth is not specified. Current emphasis upon energy conservation

dictates that the opposite condition be explored, namely, where output stops growing or even diminishes.<sup>18</sup>

The effect of this condition depends upon when it occurs.

If growth stops or is retarded when the existing plant is operating near the point of full utilization, new plant can be postponed. This delays the cost spike associated with a major new facility which at the outset will be only lightly loaded. If the new facility is more expensive than existing facilities, the higher costs of such facility also will be delayed.

On the other hand, if growth stops when the existing plant is operating well below full utilization, with plenty of spare capacity, the decreases in unit costs which otherwise would be achieved are sacrificed. Negative savings result.

In the first situation, the costs of demand-side management or other energy conservation measures will be offset in whole or in part by

- a) The savings in capital costs resulting from the delay of the investment in the new plant which otherwise would be required earlier, or (the same in different terms)
- b) The savings in per-unit costs resulting from the delay in the cost spike which otherwise would be experienced earlier.

In the latter case, there is no offset to the costs of energy conservation (except, perhaps, at some indefinite future time) and in addition to conservation costs, are costs equivalent to the per-unit costs savings which are foregone as a fuller utilization of the plant capacity is prevented or delayed. If the effect of conservation is so extreme as to cause a reduction in output below the prevailing level, the costs to be added to the costs of conservation will include not only the above-mentioned foregone savings in future lower per-unit costs, but also the increase to higher earlier levels of per-unit costs arising from the reduction in output.

There is no doubt that the reduction in output entails serious problems whatever the cause. The cause may be conservation, loss of load due to bypass, price elasticity, economic recession—it doesn't matter. Customers pay more for using less. They do not take kindly to such treatment from their energy supplier.<sup>19</sup>

Because there are so many variations in the timing and specific nature of the costs which must be dealt with in evaluating this no-growth scenario, we do not attempt to devise illustrations. A reexamination of the earlier tables, this time approaching them from the bottom-up rather than from the top-down, will give a bird's-eye view of the utility's internal dynamics.

### ***2.9.7 Summary of Findings***

The summary scenarios (Tables 2.7, 2.9, and 2.11).

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<sup>18</sup>The writer is tempted to quote the question which appeared in a different context in bold type on the cover of the May 16, 1994 issue of *Business Week*: "Why are we so afraid of GROWTH?"

<sup>19</sup>This problem is discussed in relation to price elasticity in Chapter 5.

(1) Each shows decreasing per-unit fixed costs as the utilization of capacity improves. This is an axiomatic result.

Taking the full five plant systems as illustrative for each case, in index numbers with the unit cost at an 80% dependable energy capacity factor as 100, unit costs decline as shown in Table 2.25:

**Table 2.25** Decline in fixed costs with improvement in utilization

Dependable energy capacity factor	Plants #1–#5 (80% DECF = 100)		
	Dec.	Constant	Inc.
80%	100	100	100
90	89	87	89
100	80	79	80

(2) The impact on per-unit fixed costs of the changing magnitude of the added costs for each output addition is felt for the decreasing and increasing cost scenarios, but the composite (rolled-in) unit cost change is less than the change in the new investment costs.

*Decreasing costs:* For this scenario, investment and other fixed costs per billion kWh of dependable output declined to \$27 million for Plant #4 and to \$26 million for Plant #5, as compared to \$30 million for the base system. These declines are 10 and 13%, respectively.

Associated fixed costs per unit, at a 100% dependable energy capacity factor, declined to 2.9 cents per kWh with Plant #4 online, and to 2.8 cents per kWh with both Plants #4 and #5 online, as compared to 3.0 cents per kWh for the base system, declines of 3 and 7%, respectively. (Table 2.26)

Thus,

**Table 2.26** Decline in costs with decline in investment

	Decline in new investment	Decline in composite per kWh cost
4 Plants	10%	3%
5 Plants	13%	7%

The impact of new investment at a lower cost will be dampened by compositing new with old higher-cost investment to reach a rolled-in per kWh cost.

*Constant costs:* By definition, the relationships remained unchanged.

*Increasing costs:* Here investment costs are increased to \$40 million for Plant #4 and to \$45 million for Plant #5, from the \$30 million for the base system, increases of 33 1/3 and 50%, respectively.

With Plant #4 online, unit costs rose to 3.3 cents per kWh at 100% dependable energy capacity factor, and to 3.6 cents per kWh with both Plants #4 and #5 online, rising from 3.0 cents per kWh for the base system, increases of 10 and 20%, respectively. (Table 2.27)

Thus,

**Table 2.27** Increase in costs with increase in investment

	Increase in new investment	Increase in composite per kWh cost
4 Plants	331/3%	10%
5 Plants	50%	20%

The impact of new investment at a higher cost will be damped by compositing new with old lower-cost investment to reach a rolled-in per kWh cost.

Assuming the same overall fixed cost per unit of output (which assumption disregards the economies of scale), a series of small capacity additions will be less expensive in terms of fixed costs than equivalent larger additions. However, variable costs may be higher.

Power exchanges with other systems often may be the best route when a utility is deficient in either peaking or energy. However, a peaking plant is an alternative for a peaking deficiency provided its cost is viable and/or there is a robust interruptible market for surplus energy.

**Purchases:** If a utility needs additional energy, and if the price is right, power purchases from non-utility sources may be a least-cost alternative to utility-constructed new capacity.

**Bypass:** The impact of bypass is destructive, the degree of the harm being dependent upon the size of the revenue loss.

**Discounted prices:** If a utility is permitted to offer a discounted (competitive) price to a potential bypasser, the revenue loss is only partial, not full. Thus, the destructive impact of bypass is mitigated. However, the question of whether a discounted price offered on only a limited basis is discriminatory, must be faced.

When growth within the capacity of existing plant is arrested by conservation, the per-unit economies of fuller utilization are postponed.

When growth requiring new plant is arrested, the cost spike and the investment in new plant are postponed. Depending upon whether the new plant is more or less expensive, either higher or lower unit costs also are postponed.

The costs of conservation measures will either be a reduction in the advantages of postponement, or an addition to the disadvantages, depending upon the circumstances of occurrence.

## 2.10 Variable Costs

Oil, natural gas, and coal are the three most common fuels used for electric generation. The costs of purchasing these fuels comprise the most important variable costs of the electric utility.

Natural gas is the commodity transported and/or sold by gas pipelines and distributors. If the cost of buying this gas at the wellhead (i.e., the price paid to the producers) is commingled with the pipelines' and distributors' other costs, it

becomes by far the most important element of their variable costs. On the other hand, if the gas itself is considered simply to be a commodity transported long distance by pipelines and distributed locally by distributors, as a railroad or other common carrier transports freight, it is not a part per se of the cost package of these utilities. From this viewpoint, it can be excluded from their variable costs, which for pipelines then would consist only of the ebb and flow with volume of relatively minor non-fixed expenditures for operations and maintenance. For distributors, a part of their pipeline bills would be fixed, with other parts being variable, together with most O&M expenses.

To this point, except for Table 2.1 and Fig. 2.2, variable costs have not been incorporated into the cost analysis. This has been done for different reasons in the two industries.

For the electric industry, while the costs of fuel for generation (and other variable costs) are significant, they seldom will be sufficiently large as to change the direction of average costs away from the direction indicated by fixed costs. This is generally true even though the prices of fuel tend to be highly erratic.

For natural gas, the earlier cost analyses parallel the pipeline and distributor segments of the industry. These segments are not subject to “the tail that wags the dog” vagaries of the market-set producer price. Like electric, absent the producer share, the economics of the operations of pipelines and distributors are driven by the surge of fixed costs. And, like electric, the direction of their average costs, the producer component excluded, will tend to be the same as their fixed costs.

It is the writer’s opinion that the field price of natural gas is influenced by so many extraneous conditions as to be virtually unpredictable except relatively. The energy market, local, national, and world-wide, sets the producer price. The temptation to predict is near overpowering. It would be satisfying to be the guru of oil and natural gas prices. Many try, and these will vehemently disagree with the writer’s opinion. There is one prediction, however, which the writer thinks is safe and which may be of help in evaluating the prices (and the direction of prices) which producers will charge. It is this: for gas supplied for core residential and commercial markets, and to some degree for industrial markets as well, the producer price, after allowance for the costs of gas transmission and distribution, will continue to permit these several markets to be supplied at a burner-tip price which is competitive with other energies.

Having said that, we conclude that variable costs are just that and not only by definition. They expand and contract in total with output. But also, both in total and per unit, they may change erratically with changes in the price per barrel of oil, per mcf of natural gas, or per ton of coal. Other variable costs also may change, but in all probability less erratically.

The volatility of oil and gas prices to either utility may rest in part upon the extent to which they rely upon spot market purchases. These short-term purchases tend to be unstable both as to price and availability. Longer-term purchases, guaranteed by contract, may substitute dependability but at a higher price. A given utility may rely upon a combination of both types of supply. Some may seek a degree of price stability by venturing into the futures market or other derivatives. In any event, contrary to our prior simplifying assumption, it is unlikely that variable costs will be constant

per unit. They may differ from one generating plant to another or from one stage of production to another for a given plant. Gas supplies purchased by pipelines and distributors also will vary from one source of supply to another. The most likely pattern for these utilities is that the gas stream which they own or transport for other parties will arise from a mix of sources at a mix of prices. The constant variable costs per unit in Table 2.1 and Fig. 2.2 are illustrative, not representative.

### ***2.10.1 The Dominance of Variable Costs***

One point mentioned elsewhere needs clarification. It has been stated that to serve peak demands, the most efficient resource will be brought online first, the next efficient second, etc., until the last is the least efficient resource required to meet the peak. This is an operational rule which applies equally to generating plants owned by an electric utility, or to the purchase of energy by any utility from an outside source. “Efficient” means cheapest.

In applying this rule fixed costs do not count. They are sunk costs, which do not change with the degree of utilization. They must be met in any event. Variable costs determine the generating plant to be used. A plant having higher fixed costs will be placed online if it has lower variable costs (mainly fuel costs) than other plants. This rule applies not only to the multi-plant utility system, but also to many power pools. In a “tight” pool, all of the plants of the members are centrally dispatched as if under a single ownership. The plants in the pool are placed online in the sequence of their operating costs, from the cheapest to the most expensive.

Variable costs also determine from where and from whom energy supplies will be bought. The cost of the seller is unimportant in the short term. The seller’s price is what counts. The utility, electric or gas, will buy from the seller offering the lowest price.<sup>20</sup>

### ***2.10.2 The Uncertainty of Variable Costs***

One of the most hazardous uncertainties facing the buyer of independent power production or cogeneration power is the variable cost of these generators over time. Despite the favorable world oil situation which prevails as this is being written, another oil crisis could occur. Such recurrence would inevitably boost natural gas prices as they tend to move in tandem with escalations in the price of oil. Also, unless the nation’s evaluation of priorities to the use of energy are radically different in a future crisis than they have been in the past, fuel for electric generation will be low on the scale of energy priorities. The buyer of energy from non-utility sources will be advised to look ahead to future dependability of supply, and not focus too much on which supply appears to be cheapest at the moment.

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<sup>20</sup>With due consideration, of course, to the terms and conditions of sale—volumes, duration of contract, minimum and maximum takes, dependability, etc.

### 2.10.3 *High Capital/Low Operating Costs vs. Low Capital/High Operating Costs*

Electric policy decisions increasingly focus on whether to employ new plants having high capital but low operating costs, the predominant pattern of the past, or new plants with low capital but higher operating costs, as in distributed generation which many foresee as the pattern of the future. Large gas-fueled combined-cycle projects are a good example of the latter. A key and unavoidable ingredient of these decisions is the project developer's prognostication as to future gas prices (an area of prediction in which the writer, like the angels of the proverb, refuses to tread).

Table 2.29 illustrates the choice. As a benchmark against which to compare a gas-fired combined-cycle plant we adopt a central station with the costs found frequently in earlier scenarios, viz. (Table 2.28)

**Table 2.28** Typical central station costs

Central station costs per kWh	
Fixed costs	3.0¢
Variable costs	1.0¢
Total	4.0¢

The above variable costs do not attempt to distinguish between the types of fuels used at the central station, which may be a mix of fuels such as shown in footnote 10, *supra*, or a single fuel.

Two illustrative variations of combined-cycle fixed costs are given: at 50% of central station fixed costs, or 1.5 cents per kWh; and at 75% of the central station costs, or 2.25 cents per kWh. Variable costs are broken down into non-fuel, which is maintained at a constant 0.1 cents per kWh, with the residual representing fuel (gas) costs. Obviously, the higher the fixed costs per kWh, the greater is the competitive sensitivity of the end-result total cost to the price paid for the gas used as fuel.

To translate gas costs per kWh into the cost of gas per MMBtu we adopt a heat rate of 8,000 Btu per kWh, as proposed for this type of plant by Charles M. Studness, a contributing editor to the *Fortnightly*.<sup>21</sup> This heat rate is considerably lower (better) than the 10,000 Btu per kWh which often is used as a rough rule-of-thumb for central stations. A low heat rate is evidence of a high level of thermal efficiency of generating facilities.

The central station competitive benchmark, and combined-cycle plant costs which equate to this benchmark under the two alternative fixed-cost assumptions are enclosed in the three boxes of Table 2.29. With fixed costs at 50% of the benchmark, gas costs could be 2.4 cents per kWh or \$3.00 per MMBtu for a total cost equal to the central station; with fixed costs at 75%, gas costs could be only 1.65 cents per kWh or \$2.06 per MMBtu. The tolerance for upward fluctuations in the price of

<sup>21</sup> Studness, C.M., "The Pressures of Competition," *Public Utilities Fortnightly*, June 15, 1993.

**Table 2.29** Sensitivity of costs of combined-cycle generating plant to fluctuations in the price of gas

Cost per kwh					
Fixed cost	Variable costs			Total cost	Gas price per MMBtu <sup>a</sup>
	Non-fuel	Gas	Total		
Central station benchmark					
3.0¢			1.0¢	4.0¢	
Combined-cycle fixed costs @ 50% of central station fixed costs					
1.5¢	0.1¢	1.4¢	1.5¢	3.0¢	\$1.75
1.5	0.1	1.9	2.0	3.5	2.38
1.5	0.1	2.4	2.5	4.0	3.00
1.5	0.1	2.9	3.0	4.5	3.62
1.5	0.1	3.4	3.5	5.0	4.25
Combined-cycle fixed costs @ 75% of central station fixed costs					
2.25¢	0.1¢	0.65¢	0.75¢	3.0¢	\$0.81
2.25	0.1	1.15	1.25	3.5	1.44
2.25	0.1	1.65	1.75	4.0	2.06
2.25	0.1	2.15	2.25	4.5	2.69
2.25	0.1	2.65	2.75	5.0	3.31

<sup>a</sup> At assumed heat rate,  $\frac{\text{Gas Cost in cent /kwh}}{8} = \text{Gas Price in \$/MMBu.}$

purchased gas diminishes inversely with the fixed-costs component of the total cost. In other words, an increase of 1 cents per kWh in the total cost (from 4 to 5 cents) could contain an increase in the price of purchased gas to \$4.25 per MMBtu, with fixed costs at 50% of the benchmark. The same 1 cents increase in the total cost could contain an increase in the price of purchased gas to only \$3.31 per MMBtu, with fixed costs at 75% of the benchmark.

2.11 Matters of Judgment

Ten main tables, four charts, and a goodly number of pages of explanation and shorter tables have been devoted to the arithmetic of utility fixed and variable costs. This is necessary, for the economics of operations, and the pricing, of utilities rest upon the principles derived from an economic environment dominated by the cost mixture presented. But we cannot leave this subject with the impression that the choices facing utility managements and their regulators are merely matters of arithmetic calculation. The reality is quite the contrary. The choices are judgmental.

(1) The first choice is whether the policy should be anchored to the long-run probability of decreasing, constant, or increasing costs. Whatever the depth of the

engineering studies which are brought to bear, the selection ultimately will reflect the predilections of those making the choice. The proper numbers—the pattern of Tables 2.7, 2.9, or 2.11—will not automatically evolve.

(2) Having opted for one of the long-run perspectives, specific implementing steps for both the immediate and more distant future must be set forth. These also will mirror the mindsets of those responsible.

Under a decreasing or constant cost scenario, pricing decisions would appear to be fairly clear-cut. Prices should encourage a full utilization of plant. Energy should be available for all types of consumption which are of benefit to the economy or the well being of citizens. Conservation should be limited to the elimination of wasteful energy uses. Cost spikes are the only real problem and these can be tempered by cost averaging.

The increasing cost scenario is difficult because it is intrinsically contradictory. New capacity is more expensive, but within the capacity of existing plant fixed costs per unit decline as the plant is brought to higher utilization. Neither factor can be ignored. Which should drive price policy?

It can be argued that greater weight should be given to the decreasing cost condition of online plants since that is always present, while new plant is added only intermittently. Or it can be argued that since the long-term direction of costs is up as new more expensive capacity becomes operative, this cost direction should be decisive.

If increasing costs are taken as the bellwether, conservation measures and the expenditures for them seem to fit into a rational pricing policy. These measures retard the advance toward greater usages, and thus delay a higher-cost plateau. Prices should discourage unnecessary and luxury energy use.

Pricing generalities such as those above for the opposing alternative scenarios can be stated almost casually for they hide the real issues which go to the specifics. It is in the specifics that judgment shows its hand. For example, should all classes of customers, residential, business, agricultural, or industrial, receive the same rate treatment, or should consumption by one class be encouraged or discouraged, as the case might be, while for another class prices remain neutral and for still another, the opposite? Should one type of energy be preferred? Are generous low-cost supplies of energy for industrial use necessary for the nation's economy?

Ideological differences also enter judgmentally into the framing of price policy. As this is being written, a classic confrontation seems to be brewing between two ideologies which formerly thought in tandem. Environmentalists and conservationists have both generally opposed electric industry growth, particularly nuclear generation. Environmentalists now are promoting the electric automobile in the push for cleaner air. But the use of electricity for vehicle propulsion on any widespread scale would necessitate huge additional electric capacity. This is hardly a step toward further electric energy conservation. When the implications are realized, the reaction of energy conservationists is anybody's guess. California may soon find out.

(3) It is likely that an analyses of the utility's cost will point in different directions for different functions or different parts of its service territory. It may be, for example, that major transmission lines are heavily loaded while generating plants (for electric) or city gates (for gas) are lightly loaded. One part of operations might show

increasing costs, while another the opposite. If rates have been unbundled functionally or by area, there is no problem. Pricing for each separate bundle can follow its own cost trend. But if kept bundled, which of the opposing trends should be adopted for pricing? Again, a matter of judgment.

(4) There is a widely accepted view that today's prices should signal tomorrow's. Simple to say. But what is a correct price signal? The writer confesses to be perplexed by this question when applied to the rank and file of the utility's customers. (Big customers do not need a price signal embedded in their present rate to look forward to the future. They will be about as well informed as utility managers and regulators.) What price for current usage will advise the homeowner, small businessman, or small farmer that the price he will have to pay in the future will be higher or lower, and by how much?

Acceptance of the validity of the price signal concept is a requisite under present "political correctness" etiquette for utilities. Nonetheless, the question needs asking.

The unsophisticated customer receives a monthly bill, for a certain number of dollars. Say the bill is for \$50. If interested, the customer may read the bill more carefully and find a summary of his rate on the bill.

This may say

Customer charge:	\$3 per month
Energy charge:	10¢ per kWh (or 65¢ per therm)

What does that tell the customer about the amount of his future bills, or about the per-unit prices from which his future bills will be calculated? A common sense answer is, absolutely nothing.<sup>22</sup>

The beginning driver, to pass his driver's test, must know traffic signals. "Red" means stop. "Green" means go. "Orange" means the signal is about to change. These are clear and unambiguous. If utility customers should be informed that their bills would trend up or down, let's tell them. A brief statement on the bill would suffice. We should stop pretending that the customer has been in fact advised by a price signal which signals nothing. The writer confesses that this harangue states only his own personal view. It is a minority view.

Dropping our doubts, we return to the point, acceding *arguendo* that the price should present a proper signal to the customer. While we have admitted that we do not know how this can be achieved, we do say, safely, that the matter is one of pure subjective judgment.

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<sup>22</sup>Time-of-day or "Real Time Pricing" rates, if spelled out on the customer's bill, are effective in advising the customer that it is cheaper or more expensive to use energy at one time period or another, and thus may influence the customer's usage pattern. But the signal they send is a *current* message. They tell nothing about the level of *future* rates. Even rates with inverted blocking do not signal the future.

## 2.12 A Note on Generating Plants

Operationally, there are two types of generating plants on the mature utility system, *baseload* and *peaking*. Baseload plants are built to operate continuously, in the load valleys throughout the night as well as during the daytime hours. They have heavy fixed costs, but these are low per unit because they are spread over a large volume of kilowatt-hours. Variable costs tend to be low also, except for large changes in output (“ramping” the level of output up or down). Peaking plants, as the name suggests are used intermittently to carry increases in load beyond the capability of baseload plants. Their fixed costs are lower than for baseload units, since they do not need as many built-in safeguards, but their variable costs tend to be higher.

“Distributed Generation” is a somewhat recent development. The term involves the use of small-scale electric generating technologies installed in, or in close proximity to, the end-users location. The facilities may be internal combustion engines, combustion turbines, wind turbines, photovoltaics, or fuel cells. They may be located at disbursed customer or utility premises. They may be stand-alone or system-integrated. They may range in capacity from a few kilowatts to over 100 MW, although they usually are only one-tenth the size of units recently thought to be most economic. Combined-cycle gas turbines may require as little as one-third of the capital investment required for a new coal-fired unit.

Distributed generation units are strategically placed to have localized benefits in the generation, transmission, and distribution systems. They may replace central stations as the primary source of incremental power. Robert L. Hirsch, a highly qualified expert, declared in 1996, “Gas-fired, combined-cycle power generation has developed into the least expensive, easiest, fastest to site, environmentally attractive choice for new central station electricity generation. Accordingly, a large portion of new electrical power generation is gas-fired combined cycle.”

“Cogeneration” is a subset of distributed generation. It consists of the use of a heat engine, such as a combined-cycle turbine, to simultaneously generate both electricity and useful heat. The excess heat is used in the manufacture of the product produced by the operator. This heat is wasted in a conventional power plant.

## 2.13 A Note on the Level of Costs

The levels of the fixed and variable costs adopted earlier in this chapter for generating plants are necessarily arbitrary, due to the variety of circumstances which influence plant design, size, type, choice of fuel or fuels, and age. A further question is whether or not ancillary services, such as load following, reactive power support, and system protection, should be included in the cost. Individual utilities have special operational problems. For example, Pacific Gas and Electric Company operates specific generating units to provide critical voltage support, thermal relief, and stability to its transmission system, and has designated certain

plants as “must run” generation. These assignments influence both categories of costs.

Faced with these uncertainties, we have devised middle-of-the-road cost data for use in our examples, ignoring extremes on either side. We note, however, that these figures seem to fall within a wide range noted by Rebecca Smith, writer for *The Wall Street Journal*. She reported NRG Energy Inc., as a prospective buyer, had offered to pay the equivalent of \$600–700 for each kilowatt of generating capacity it wanted to acquire from Calpine Corp., but its offer had been rejected because Calpine claimed that its replacement cost was \$1,000–1,200 per kW.<sup>23</sup> However, another writer, at about the same time, gave a “notational” cost of \$5 million per MW for a new 1,000 nuclear-powered plant. This translates to \$5,000 per kW.<sup>24</sup>

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<sup>23</sup>Smith, R., “NRG After Rejection, Ends Calpine Effort,” *The Wall Street Journal*, June 1, 2008.

<sup>24</sup>Denning, L., “Energy Prey Can Find Partners,” *The Wall Street Journal*, November 14, 2008.



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