

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed



Energy solutions
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Table of Contents

List of Figures	3	3. Fixed Period Time-of-Use	28
Abbreviations and Acronyms	4	4. Combining Inclining Blocks With Time-of-Use Rates	29
About the Global Practice Series	5	5. Prepayment	29
Foreword	6	6. Low-Income Rate Programs	30
Executive Summary	9	7. Dynamic Pricing	30
1. Introduction	11	D. Residential Pricing for Distribution Utilities	30
2. Framing	13	E. Power Supply-Only Rates	31
A. Structure of the Paper	15	F. General Service	32
B. Principal Pricing Approaches Examined	15	i. Small Commercial	32
C. The Division Between “Simple” and “Advanced” Metering	16	1. Monthly Fixed Charge	32
D. Goals of Retail Pricing	16	2. Demand and Usage Charges	32
E. Types of Utilities	17	3. Innovative Concepts in General Service Pricing	33
F. Different Ways of Measuring Cost	17	a. Time-of-Use	33
G. The Process of Retail Pricing	18	b. Dynamic Pricing	33
3. Elements of Traditional Rate Designs	20	c. Rolling Baseline Rates	33
A. Customer (Monthly Service) Charges	20	G. Large User Pricing	33
B. Energy Charges	20	i. Monthly Fixed Charge	34
C. Demand Charges	21	ii. Facilities, Demand, and Usage Charges	34
D. Demand Ratchets	22	iii. Time-of-Use vs. Real-Time Pricing	34
E. Load-Factor Rates	22	iv. Innovative Concepts: Rolling Baseline Rates	34
4. The Principles of Rate Design and Some Issues Arising From Them	23	v. Dynamic Pricing	34
5. Rate Design Basics and Examples	25	H. Special Contracts	34
A. Integrated vs. Restructured Utilities	25	6. Treatment of Carbon Dioxide and Other Emissions Costs	36
B. Basic Tariff Designs	25	7. Tariff vs. Market-Based Pricing	37
C. Beyond Basic Usage Rates for Integrated Utilities	26	A. Traditional Tariff Pricing: Rates Defined Until They are Changed	37
i. Residential	26	B. Market Prices	37
1. Monthly Fixed Charge	26	C. Long-Term Contract Prices	37
a. Customer-Specific Facilities	26	D. Adjustment Clauses	37
b. Shared Facilities	26	i. Fuel and Purchased Power	38
2. Block Rate Design	27	ii. Environmental Cost Recovery	38
a. Load Shape Considerations	27	iii. Energy Efficiency Programs	38
b. Resource-Based	27	iv. Decoupling and Revenue Stabilization	38
c. Vintage	27	v. Smart Grid	39
d. Revenue Requirement-Constrained	28	vi. Infrastructure	39
		vii. Taxes and Franchise Fees	39
		viii. A Sample Utility Bill With Adjustments	40
		ix. Voluntary Environmentally-Preferred Power Programs	40

8. Pricing for Small Power Producers	41	B. Residential Low-Income	54
A. Wholesale Power Payment	41	i. Seattle City Light Low-Income Rate	54
B. Net Metering.	41	ii. UK Fuel Poverty Program	55
C. Feed-in-Tariffs.	41	iii. Met-Ed (Pennsylvania) Percentage of Income Payment	55
D. Bidirectional Distribution Pricing	42	C. Commercial	55
9. Transmission & Distribution		i. British Columbia Rolling Baseline Rates	56
System Expansion Planning and Charges	44	ii. Contrast: High- vs. Low-Demand and Facilities Charges	56
A. Connection and Service Extension	44	D. Industrial	57
i. New Service Territory Expansion	44	i. Washington Real-Time Pricing	57
ii. New Customer Connections	44	ii. Georgia Power Baseline-Referenced RTP	58
iii. Increased Customer Capacity.	45	iii. China Output/Unit-Based Curtailment.	58
iv. Disconnection/Reconnection	46	iv. BPA Large New Single User Rate	58
v. Late Payment, Bad Checks, and Other Miscellaneous Charges	46	E. Connection Charges	59
10. Revenue Stability	47	i. Indonesia PLN Capacity-Based Charges	59
A. Straight Fixed/Variable Pricing	47	ii. Idaho Feebates.	59
B. Lost Revenue Adjustment Mechanisms	47	iii. Mason County Code Substitute	59
C. Revenue Regulation and Decoupling	47	12. Recommendations and Conclusions	60
D. Rate Design Comparisons	48	A. Be Forward-Looking and Focus on the Long-Term	60
11. Examples of Global Best Practices	50	B. Recover Costs on Usage-Sensitive Rate Elements.	61
A. Residential	50	C. Empower Consumers to Respond Effectively to Rates	61
i. Western US Inclining Residential Block Rates	50	D. Consider Some Form of Dynamic Pricing as an Optional Service.	61
ii. Andhara Pradesh Residential Block Rate	51	E. Complement Effective Price Signals with Effective Policies and Initiatives.	62
iii. ESKOM South Africa Electrification, Prepayment, and Pricing	52	13. Appendix A: Elasticity Effect on Three Residential Rate Designs	64
iv. Indonesia Perusahaan Listrik Negara Social Tariff	52	14. Bibliography	68
v. Southern Electric (UK) 3-Year Contract Price.	53		
vi. Southern California Edison (and Others) Air Conditioning Interruption Rate Discount.	53		
vii. Hungary Residential Rate Design	54		

List of Figures

Figure 1.	Simple Residential Tariff	25
Figure 2.	Simple Small Commercial Tariff.	26
Figure 3.	Basic Tariff for Large Commercial Customer	26
Figure 4.	Illustrative Hourly Usage of Residential End-Uses	27
Figure 5.	Utility Resource Supply and Cost	27
Figure 6.	Vintage Rate Design.	27
Figure 7.	Residential Inclining Block Rate.	28
Figure 8.	Residential Fixed Period TOU Rate	29
Figure 9.	Residential Seasonal TOU Rate with Inclining Blocks	29
Figure 10.	Prepayment Tariff Compared To Billed Tariff	30
Figure 11.	Residential and Low-Income Residential Rate	30
Figure 12.	Residential Electric Distribution Tariff	30
Figure 13.	Standard Offer Service For Power Supply	31
Figure 14.	Fixed Price Power Supply Tariff.	31
Figure 15.	Green Power Offering	31
Figure 16.	Simple Small Commercial Tariff.	32
Figure 17.	Basic Tariff For Large Commercial Customer.	32
Figure 18.	Residential Fixed Period TOU Rate	32
Figure 19.	Rolling Baseline Rate	33
Figure 20.	Rate for Large User (over 250 kVA demand)	34
Figure 21.	Rate Surcharges and Refunds under Revenue Decoupling	39
Figure 22.	Comparison of “Itemized” and “Rolled-up” Bill	40
Figure 23.	Bidirectional Renewable Power Tariff.	42
Figure 24.	Line Extension Policy	44
Figure 25.	New Customer Connection Standard	45
Figure 26.	Comparison of Four Residential Rate Design Alternatives	49
Figure 27.	Actual Inclining Block Rates – Western United States	50
Figure 28.	Actual Rates of California Investor-Owned Utilities	51
Figure 29.	Andhra Pradesh (India) Residential Tariff	51
Figure 30.	ESKOM Residential Tariff at November 6, 2011	52
Figure 31.	PLN Indonesia Residential Tariff Prices	53
Figure 32.	Southern Electric (UK) Three-Year Fixed Tariff	53
Figure 33.	Southern California Edison Summer Discount Plan.	54
Figure 34.	Residential Electricity Prices in Hungary	54
Figure 35.	Seattle City Light Residential and Low-Income Discount	55
Figure 36.	BC Hydro Rolling Baseline Large Commercial Rate	56
Figure 37.	Comparison of Two Rural Electric Cooperative Rates, One with High Demand Charge, One Low Demand Charge	57
Figure 38.	Real-Time Prices During the 1996-2001 Puget Sound Energy RTP Program	57
Figure 39.	Bonneville Power Administration Average Wholesale Rates	58
Figure 40.	Embedded and Marginal Costs Illustrative (Not From a Specific Utility)	60

Table of Appendix A Figures

Figure A-1. Three Basic Rate Designs 67
 Figure A-2. Bill Impact of Three Rate Designs 68
 Figure A-3. Distribution of Customers By Usage Level 68
 Figure A-4. Residential Revenue With Flat Rate 68
 Figure A-5. Elasticity Effect of Inclining Block Rate on Customers Ending in First Block 69
 Figure A-6. Elasticity Effect of Inclining Block Rate on Consumption of Customers Ending in Second Block 69
 Figure A-7. Elasticity Effect of Inclining Block Rate on Consumption of Customers Ending in Third Block 69
 Figure A-8. Combined Effect of Inclining Block Rate Design 70
 Figure A-9. Effect of Straight Fixed/Variable Rate Design 70

Abbreviations and Acronyms

AMI	Advanced Metering Infrastructure	PUD	Public Utilities District
AP	Andhra Pradesh	PURPA	Public Utilities Regulatory Policies Act
BPA	Bonneville Power Administration	RPC	Revenue Per Customer
CAP	Customer Assistance Program	RTP	Real-Time Pricing
CPP	Critical Peak Pricing	SCE	Southern California Edison
DBR	Declining Block Rate	SE	Southern Electric (UK)
kWh	Kilowatt Hour	SFV	Straight Fixed/Variable
kVA	Kilovolt Ampere	SRMC	Short-Run Marginal Cost
LRAM	Lost Revenue Adjustment Mechanism	T&D	Transmission & Distribution
LRMC	Long-Run Marginal Cost	TOU	Time Of Use
MDMS	Meter Data Management Systems	TSLRIC	Total System Long-Run Incremental Cost
PLN	Perusahaan Listrik Negara	VA	Volt-Amperes

About the Global Power Best Practice Series

Worldwide, the electricity sector is undergoing a fundamental transformation. Policymakers recognize that fossil fuels, the largest fuel source for the electricity sector, contribute to greenhouse gas emissions and other forms of man-made environmental contamination. Through technology gains, improved public policy, and market reforms, the electricity sector is becoming cleaner and more affordable. However, significant opportunities for improvement remain and the experiences in different regions of the world can form a knowledge base and provide guidance for others interested in driving this transformation.

This Global Power Best Practice Series is designed to provide power-sector regulators and policymakers with useful information and regulatory experiences about key topics, including effective rate design, innovative business models, financing mechanisms, and successful policy interventions. The Series focuses on four distinct nations/regions covering China, India, Europe, and the United States (U.S.). However, policymakers in other regions will find that the Series identifies best — or at least valued — practices and regulatory structures that can be adapted to a variety of situations and goals.

Contextual differences are essential to understanding and applying the lessons distilled in the Series. Therefore, readers are encouraged to use the two supplemental resources to familiarize themselves with the governance, market, and regulatory institutions in the four highlighted regions.

The Series includes the following topics:

1. New Natural Gas Resources and the Environmental Implications in the U.S., Europe, India, and China
2. Policies to Achieve Greater Energy Efficiency
3. Effective Policies to Promote Demand-Side Resources
4. Time-Varying and Dynamic Rate Design
5. Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed
6. Strategies for Decarbonizing the Electric Power Supply
7. Innovative Power Sector Business Models to Promote Demand-Side Resources
8. Integrating Energy and Environmental Policy
9. Policies to Promote Renewable Energy
10. Strategies for Energy Efficiency Financing
11. Integrating Renewable Resources into Power Markets

Supplemental Resources:

12. Regional Power Sector Profiles in the U.S., Europe, India, and China
13. Seven Case Studies in Transmission: Planning, Pricing, and System Operation

In addition to best practices, many of the reports also contain an extensive reference list of resources or an annotated bibliography. Readers interested in deeper study or additional reference materials will find a rich body of resources in these sections of each paper. Authors also identify the boundaries of existing knowledge and frame key research questions to guide future research.

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Foreword

Together, this paper and its companion piece, Time-Varying and Dynamic Rate Design, examine the wide spectrum of retail pricing practices for regulated energy services and identify those that have particular promise in contributing to the achievement of critical public policy objectives, which we might broadly categorize as equity, efficiency, and the sustainable use of our finite natural resources. The papers should prove an excellent resource for policymakers, power companies, advocates, and others as they navigate the arcana of utility pricing and engage on a topic that has, by virtue of advances in information technology and changes in the underlying economics of power production and delivery, become at once more complex, more controversial, and, too often, more distracting.

The complexity and controversy are not avoided in these papers. Though for the most part they express views that are consistent with those of the Regulatory Assistance Project, it is not true in all cases. This is a virtue. We embrace the dialectic: over the coming months and years we will continue to work on these issues, follow progress globally, and re-examine our views in the light of new findings. These papers are only our most recent look at the state of the art. There will be others.

Still, a few comments today are warranted. Regulators are constantly told to “get prices right,” a refrain whose meaning is more easily understood in the speaker’s mind than it is conveyed to those who must put it into practice. In our experience, the prescription must be taken with two doses of reality’s practical learning: one, that getting prices “right” is by no means straightforward and, two, that, even if one manages to set prices that in some fashion might be called “right,” some of the key objectives of pricing will nevertheless remain unmet. Foremost among them is overcoming society’s very serious underinvestment in cost-effective energy efficiency and other clean energy resources, and it is primarily for this reason that we say that pricing reform must be dealt with in a much broader policy context.

But, first, what is “right”? The question has surely been debated since governments began pricing these services “affected with the public interest,” but the form of the debate only began to take its modern shape in 1949 with the publication of Marcel Boiteux’s “La Tarification des demandes en pointe,” which gave renewed currency to certain prerequisites for economic efficiency: one, that those who cause a cost to be incurred should pay that cost and, two, that, by paying, the cost-causers will necessarily comprehend the real value of the resources that they are committing to their consumption.¹ Here was a practical application of neoclassical economic theory to the pricing of networked utility services, and it was very influential.

The seminal work in English on the topic followed in 1961: James Bonbright’s *Principles of Public Utility Rates*.² In it, Bonbright identifies ten criteria to be considered when setting utility prices and acknowledges, importantly, that they cannot all be entirely satisfied simultaneously. There will always be trade-offs. Nine years later, Alfred Kahn published *The Economics of Regulation*, which, among other things, made the case for subjecting to competition certain regulated services, when those services no longer exhibit the characteristics of natural monopoly.³ Thus, in two decades, the intellectual foundations for a range of reforms in utility regulation were set and, in the thirty years since, we’ve seen extraordinary changes in the provision and pricing of air travel, telecommunications, electricity, and natural gas—that is, in essential infrastructural industries—around the globe.

But, for all that, the question of how to get prices right remains. Bonbright can’t be evaded. What constitutes economically efficient pricing? Should efficiency be the primary objective and, if so, how can it be ensured without

1 Boiteux, 1949.

2 Bonbright, 1961.

3 Kahn, 1970.

a proper accounting of environmental damage costs and other unmonetized externalities, both positive and negative, that attend the production and consumption of electricity and gas? What are the benefits of participation in a network and do they justify approaches to pricing that will, in the eyes of some, offend Boiteux's injunctions? What is equitable? How does the underlying market structure—monopolistic, regulated, or competitive—affect pricing? Are prices in competitive markets “better” than their administrative analogues? How does pricing influence consumer behavior, and how does that behavior influence utility incentives to invest? How will utility revenues be affected by different pricing structures or, more to the point, how will utility profitability be affected? How complex is the pricing structure? Can it be easily understood by consumers and easily administered by the utility? In short, how are the competing objectives balanced? What kinds of pricing will achieve preferred outcomes?

These are complicated questions all. Their answers deserve careful analysis and even more careful judgment. Dogmatism is unhelpful: the tools of economics, powerful and important, are nonetheless limited. It isn't enough to say “Let the market decide.” On the contrary, in certain instances, it's irresponsible. Design matters. Markets may deliver what they're intended to deliver, though not always in ways expected, but rarely do they deliver that which is desired but unvalued. And it's very difficult to fix them after the fact. For proof of this, one need look no further than the United Kingdom, which is facing the unpleasant prospect that its electric markets are unlikely to produce the amounts and kinds of resources that it needs to meet its own climate protection goals. Or New England, whose forward capacity market was the first to permit end-use energy efficiency and other demand response resources to participate in the provision of reliability services, but which worries now that the market fails to properly compensate the providers of those services. Such shortcomings counsel us to move cautiously before trying to drive behavior by the passing-through to retail customers of market prices, if we cannot be confident that the consequences they bear will best serve the public good.⁴

As a general matter, encouraging customers to manage their consumption in response to price signals, so that the efficiency and value of their usage increases, is a good thing. Retail prices should relate to the underlying costs

of production—all costs, including those we can't easily calculate. This is the economist's argument—at once academic and practical, for the most part uncontentious, and always invoked. Its implications, however, can overwhelm. If we find that our approach to energy production and use is impossibly sustainable, then it is no longer possible for policymakers to accept the exalted principle *and then promptly ignore it*.

But let's imagine that prices do cover all costs. There are still the practical aspects of pricing to be dealt with. How are those costs best represented in prices? George Bernard Shaw's famous snort —“If all the economists were laid end to end, they'd never reach a conclusion”—is not more aptly demonstrated than by the mavens of regulation who debate this point ad nauseum, and often at a pitch that belies the significance of the effects that their favored alternatives will likely produce. What is the thing sold? How should its prices be denominated? What should be the price's level and periodicity? Should it vary temporally and, if so, at what intervals? Should it pass through, from moment to moment, actual wholesale commodity prices or are there less volatile means of reflecting time- (and, in certain cases, location-) dependent costs? How should the costs of poles and wires be recovered? Should costs that appear fixed in the short term be collected in unvarying and unavoidable fees, unrelated to usage? Should price levels be determined with an eye to elasticities of demand?

There are other considerations. Some of the more innovative and beguiling price structures being proposed

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- 4 Another example will demonstrate that this is not an abstract concern. Consider that under most market structures firms are rewarded for increasing the utilization of their existing capacity. In the power sector, this means that profitability will increase as system load factors (the ratio of total consumption to maximum potential consumption, given actual peak demand) increase. As a practical matter, this is achieved through the shifting of on-peak demand to off-peak hours, when marginal costs are lower. Total system costs will be lower as well; everyone is better off. But what if incremental on-peak demand is served by low- or non-emitting resources and incremental off-peak demand is served by highly polluting ones? This is precisely the conundrum faced at times in places such as the Midwest, where on-peak usage is met at the margin by natural gas production, while off-peak usage variations are often served by ramping the output of coal-burning plants up and down.

require significant investment in new technology and data telemetry. Establishing that there are positive net benefits from these investments is by no means straightforward, especially when the full effects on behavior of the pricing structures they enable are imperfectly appreciated. And what about the customers who, for whatever reason, cannot react to the signals they are given and thus are harmed? That harm might be appropriate as a general matter (if we are true to the “the cost-causer pays” theme) and the overall public good may outweigh the losses of the relative few, but there are some customers for whom a change in the status quo can have altogether deleterious effects, whose private pain will be, along other dimensions of welfare, disproportionate to the good achieved. What sickness then is this medicine healing?

We recognize that more dynamic, time-varying pricing enabled by smart grid investment holds much promise. But, as we see it today, its value lies not so much in the responsiveness of customers to such pricing (although there is certainly value there) as in the new and expansive opportunities that it offers system operators to design and run the system that we must have, if we are to succeed in the great task remaining before us. That new system will be one in which the variability of supply, variable because the resources that drive it—sun, wind, water—do not submit easily to human timetables, will be matched by variable load, variable not so much because a million individual demanders respond to changes in price but because the exercise of their discretion will have been placed (to be sure, voluntarily) into the hands of system operators and other market actors. A decarbonized power sector will not come about merely because customers respond to price fluctuations. There are too many other influences on behavior that confound “rational” economic thinking on the parts of users. Moreover, as the dynamic pricing pilots around the United States and elsewhere are consistently demonstrating, retail responsiveness to price rarely manifests itself as overall reductions in energy use, but almost entirely in the shifting of use in time—that

is, it mostly affects demand for capacity, not demand for energy. Yet, far and away, the problem—the environmental problem—is energy.

Much can be done with current technologies. The United States, for example, has had decades of experience with inclining block, seasonally-differentiated, and simple time-of-use pricing structures. They’ve sent meaningful, albeit rough, signals about the varying costs of production across time, and have led to significant long-term changes in consumption habits. In 2005, China adopted a policy of “differential pricing,” whereby industrial users pay prices that are linked to the efficiency of their manufacturing: the less efficient the process, the higher the unit price for electricity. Five years later, China mandated that residential inclining block pricing be implemented throughout the country, and has instructed provincial regulators to design the blocks so as to best address the particular consumption characteristics of their populations. One size does not fit all.

There is much yet to learn. A number of pilots have been conducted and more will follow. Pricing will evolve over the coming years. The movement toward new forms must be deliberate and considered, calculated to yield the greatest long-term benefit for all. This will be especially challenging in a system that does not allow all the costs of production to be reflected in price and in which the consequences of this failure are not immediately felt. But even this ideal, were it achievable, would not be enough to effect the hoped-for ends. Economics is too uncomplicated a construct to provide sure solutions for so complicated a problem. Anyway, there are at our disposal less expensive means to drive investment and encourage new-shaped behavior. For these reasons and others besides, pricing must remain within the province of thoughtful public policy. Our intent with these papers is to expose to the reader the many and varied approaches to energy pricing that practice and technology afford us, and to sound too a gentle note of caution. All that glitters, as the old saw goes, isn’t gold.

David Moskowitz Frederick Weston

Executive Summary

The pricing of electricity service, or rate design, has a rich history in utility regulation and economic theory. Rate design, for purposes of this paper, pertains to the administrative determination of electricity pricing.⁵ As this paper and the accompanying paper on dynamic rate design reflect, rate design is a topic that is increasingly intertwined with the growing market-based service opportunities enabled by the newer and more advanced metering technology.

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted below is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run impacts of production and usage. This may include the differentiation of prices over short periods through time-varying rates. While new technology is enabling innovations in rate design, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change. The focus of this paper is on rate design that is normally associated with conventional metering technology.

This paper focuses on rate design for residential and small commercial customers. The paper also looks beyond these broad groupings to address rate design for larger commercial and industrial customers, small producers of energy, low-income customers, and special issues, like the expansion of service to new customers. Large commercial and industrial customers have historically enjoyed greater access to pricing options that previously were only possible with more advanced and expensive metering technology.

This would include time-of-use pricing and some forms of dynamic pricing. Improvements in the technology and declining costs are now enabling their use with mass market customers, but some caution is in order to ensure that customers are able and willing to comprehend and use such rates effectively.

This paper highlights sound pricing practices that exist or have existed in various regions of the world. The goal here is to expand the horizons of regulators and policymakers that are interested in considering a variety of options. In the process it also attempts to provide a firm foundation for some of the most common types of pricing, and the processes or methods that have been used to develop these prices.

James Bonbright prepared his seminal work in 1961 on the topic of pricing regulated utility services in *Principles of Public Utility Rates*. Bonbright identified eight criteria to be considered when setting utility prices. In our analyses of the form and effect of different types of rate design, we distill this list to five guiding principles.

First and foremost, prices should ideally be forward looking and reflect long-run marginal costs (LRMCs) for future resources, including production, transmission, distribution, administrative costs, and environmental costs. In most parts of the world, per-kWh rates fall short of this standard.

Second, a rate design must be simple enough for the customer to understand. Different types of customers can comprehend different levels of complexity in rate design. The level of sophistication generally increases with the customers' consumption levels and the amounts they spend for electricity. Having relatively simple default pricing, with

5 The term "prices" is universally used to represent the amount that consumers pay for service. The term "rates" is used interchangeably with "prices" in the United States, but often conveys a different meaning in British English (property taxes). As used in this document, "rates" always means the same as "prices."

more complex options added on as necessary, allows for that flexibility.

Third, prices should concentrate on the energy or usage-sensitive components of service if they are to encourage consideration of economic alternatives to grid-supplied resources, for example, energy efficiency and customer-sited energy production. Energy usage drives the vast majority of the costs of most utilities, including fuel, purchased power, investments in base load generation, the cost of transmission from remote plants, and the shortening of the useful lives of transformers.

Fourth, if utility system costs vary by season or time of day, or if a significant portion of utility investment is driven primarily by load in particular months or particular hours of the day, efficient pricing should reflect these cost drivers. But it is crucial to consider this on a total system basis – in many cases, shifting loads from on-peak periods to off-peak periods may cause environmental harm if it means additional reliance on coal-fired generation.

Finally, there are costs of environmental externalities that are not paid by utilities, and there are cost changes over time that may not be reflected in the utility's current revenue requirement. Both of these factors tend to justify pricing that has higher-than-average prices for incremental consumption, because it is at the margin where changes in behavior and usage patterns can occur.

These guiding principles, ultimately derived from Bonbright's criteria, guided the choice of practices described in this report. This report offers many examples of sound practices around the globe that may serve as a reference for jurisdictions in other regions. The examples are varied in nature, but generally exhibit certain key characteristics including the following, which represent prescriptive recommendations from this report.

Recommendation One: As the principles highlighted above suggest, sound pricing should be forward-looking and ideally long term.

Recommendation Two: The sound pricing should focus on the most cost- and price-sensitive components of service, which are generally the usage components of service. Despite the relatively capital intensive character of utility services, most services are generally sensitive to price over the long term, and should be priced accordingly.

Recommendation Three: Rate design must recognize the customer's point of view, and, as appropriate, either simplify the rate design or appropriately empower the consumer to effectively and optionally take advantage of more complex rate designs. Empowerment may come in different forms, but should include rates that are no more complex than they need be, ample opportunities for customer education, adequate explanation on customer bills, and appropriate feedback mechanisms (e.g., in-home displays or web presentment) that will allow consumers to respond effectively to even more complex optional rate designs.

Recommendation Four: Consideration should be given to providing customers access to some form of dynamic pricing. Advanced metering infrastructure is making it economically feasible to introduce more complex and market-based pricing to the mass-market (i.e., residential and small commercial) customers. Dynamic pricing can be structured to send long-term, or at least longer-term, price signals. Eventually, reflecting changing market and system conditions may be among the dominant features of dynamic pricing. Empowering consumers to respond to these changing circumstances may be needed for both consumer benefit and system gain.

These recommendations are meant to guide regulators in assessing and ultimately choosing the best pricing options available. However, even while this paper serves to underscore the importance of pricing, regulators and policymakers should not expect too much from pricing. The barriers to efficiency in the power sector are too great to be overcome by pricing alone. Most consumers who have electric service will pay a very high price to keep it flowing to their televisions, their lights, and their refrigerators. Evidence from Alaska, Hawaii, the Caribbean, and other remote places with diesel-generated electricity that costs three or even five times continental prices demonstrates this – energy inefficiency is nearly as prevalent in high-cost areas as in low-cost regions. Although price elasticity definitely exists⁶, and its influence grows with time, most studies show it is quite low, especially over shorter periods. Prices are therefore a relatively blunt instrument to influence energy consumption.

6 Price elasticity is defined here as a change in consumption in response to a change in price.

1. Introduction

The pricing of electricity service, or rate design, has a rich history in utility regulation and economic theory. Rate design refers to the elements of electricity prices that form the basis of the retail customer bills. For most retail and small commercial customers, rate design typically appears on a monthly utility bill as a fixed monthly customer charge and a usage component, which is generally a per-kWh charge that is uniform across all usage in any given month. Like most aspects of electricity service and delivery, rate design is subject to regulatory or board review, often in an administrative setting.⁷

Rate design has historically been an important focus of regulators because it can be useful in advancing other public policy objectives, which include broad social and political objectives, managing or controlling potential market abuses or distortions, impacting utility performance incentives, encouraging sound investment, or advancing long-term economic and environmental objectives. These objectives often compete with each other, so a balance of consideration is needed and infused through a market surrogate, generally the judgments of regulators, oversight boards, or ministries that function in a regulatory capacity. (For purposes of the discussion, these groups will be broadly referred to as “regulators.”)

When designing retail rates, a regulator’s creativity and policy goals are often constrained by the limitations of existing meter technology. In the absence of any meter, regulators and electric providers must rely on even simpler methods for estimating usage or fairly billing customers. In some jurisdictions this may necessitate uniform monthly charges, whereas in other jurisdictions it may warrant bill estimation by surveying household appliances. One danger of such estimations is that they inevitably either over- or underestimate actual usage, thereby over- or undercharging customers for the volume of energy used.

Retail electricity meters are now available in a spectrum of complexity and capability. Simple conventional meters measure only kWh consumption since installation, and

are read at intervals, say monthly, to note the customer’s consumption since the last reading. Somewhat more complex (and more costly) meters are capable of recording not only kWh consumption, but dividing that usage between two or a small number of preset time periods (a time of use or TOU meter), recording the peak load since the previous reading (a demand meter), or both. Special meters that record usage at set intervals, such as every 15 minutes, have sometimes been used for billing very large customers or for survey research to study the usage patterns of groups of customers. At the other end of the metering spectrum, advances in communications and digital technology are bringing down the costs of advanced metering infrastructure (AMI) and so-called smart meters for the mass market.⁸ These innovations are increasing opportunities to send not only long-term average price signals (already possible using conventional meters), but also the ability to send price signals that reflect weekly, daily, hourly, or even real-time variability in system costs and conditions and to record customer usage over time intervals as short as five minutes. Sending these types of price signals through effective rates can alter retail customer behavior, affect needed capital improvements, and influence a utility’s own capital investments. Even when the most advanced meters and meter reading infrastructure are installed, however, utilities have thus far typically continued to rely on relatively simple rate designs that are discussed in this paper.

7 The discussion of rate design here does not apply to the pricing of portions of electricity service that are established outside of an administrative determination, such as portions of retail service that are provided by competitive retail providers.

8 AMI generally means the deployment of smart meters plus other data gathering and processing equipment and software to make use of the smart meters’ capabilities. The term “conventional” meters as used here means anything less than AMI, which may include electronic meters that cannot be remotely read.

Although these smart meters are gaining momentum, a majority of the world's electricity customers are still served by conventional meters.⁹ In addition, merely installing smart meters does not alone facilitate advanced pricing; meter data management systems (MDMS) investments, billing engine modifications, and sophisticated rate studies are needed to develop advanced pricing, and these may take many years to evolve after new meters are installed. Hence, the focus of this paper is on the more foundational rate design principles that are typically associated with conventional meters. This technology typically permits differentiation in the price

signal at intervals over which the billing cycle typically occurs, generally monthly, but may also include the ability to differentiate usage during on-peak and off-peak periods, as well as a customer's peak demand.

⁹ According to Pike Research, conventional meters account for the vast majority of the roughly 1.5 billion meters installed globally in 2008 (96 percent). The more advanced smart meters are only expected to account for roughly 55 percent of meters by 2020. See <http://www.pikeresearch.com/research/smart-meters>

2. Framing¹⁰

Retail electricity pricing provides the customer billing information that allows the consumer to decide, among other things, whether to connect to the grid, how much electricity to purchase, and the purposes to which that electricity will be put.

We begin with an overarching principle: progressive pricing policy ought, as a general matter, aim to align retail prices with the LRMCs for service. This enables consumers to make rational consumption and investment decisions, whose reasonableness persists over time. Because investments in electricity supply resources, like those in end uses – buildings, appliances, motors, industrial processes, and so on – are themselves long-lived, electricity pricing that informs consumers about the long-run cost of power is critical to reasoned comparisons of alternatives.

But the principle is not absolute. Changes in electricity resource supply costs and improvements in metering technology are making possible new pricing structures that, when combined with more flexible and energy efficient end uses, can improve the economic efficiency of electricity production and consumption in the nearer term.

The general principle of aligning retail prices with LRMCs derives from an essential feature of economic systems: the constant workings of supply and demand (even in monopolistic markets) drive systems to optimize the deployment of resources (capital, labor, and materials) and thereby maximize societal welfare in the long term.

In theory, rational and efficient markets should result in general equilibrium, where short-run marginal costs (SRMCs) and LRMCs are equal. In practice, this does not occur in the electricity market. There are potentially many reasons for this, but among them is that the value the society places on reliability means that a surplus of supply must exist in nearly all hours. The availability of surplus capacity drives SRMCs (the cost of operating the reserve capacity) far below LRMC. For this reason, general pricing based on SRMCs would result in demand far greater than is economic or would be encountered in conventional markets. By generally pricing based on long-

run costs, this uneconomic consumption is avoided, but at the same time, reliability can be assured by providing adequate revenue to support reserve capacity. Experience in New England, Texas, California, and other regions of the world has demonstrated that competitive markets operating on a short-run market clearing price basis do not assure adequate investment in what is traditionally known as “reserve capacity” that is necessary to ensure reliable service. In regions of the United States that have relied on short-run market clearing prices, it has been necessary to superimpose some type of capacity market in order to assure resource adequacy, and European markets are also moving in this direction.¹¹

But deviations from the long-run-cost pricing principle – that is, adjustments to price to reflect conditions in the short term – are warranted when the failure to do so is likely to result in persistent suboptimal outcomes, such as unacceptable levels of reliability, supply shortages, and poor investment decisions.

Consider first that, however accurately a price reflects the LRMC of production (including unpriced external costs), consumers interpret it in its immediacy – “Do I purchase now?” – given the value they expect it to provide, relative to the alternatives that their cash might otherwise buy. Typically they do not ponder, nor need they ponder, the resource consequences of their choices; if the prices of all goods and services cover the full costs of the resources used in their production, then price comparisons alone should be sufficient to drive efficient consumption decisions.

10 The principal author of this paper has extensive experience in North America, and limited experience with electricity tariffs in India, Indonesia, Ireland, China, Brazil, Mozambique, Namibia, South Africa, Hungary, Poland, Israel, and Mauritius. Figures in this paper are generally presented on a US dollar basis; we assume most readers can translate this to local currency.

11 Gottstein and Skillings, 2012.

The pricing conundrum that regulators of monopoly industries have had to grapple with, and will continue to grapple with, is how to deal with short-run changes in factor costs or system conditions without adversely affecting long-run demand or supply. If, in many cases, short-run costs were reflected in end-user prices as they would be in competitive markets, distorted consumption levels would result, simply because competitive markets typically do not invest in reserve capacity, and short-run prices would often be much higher. Conversely, while electricity consumers demand reliable service even under adverse conditions, in competitive markets based on short-run costs, prices would spike to very high levels during such conditions; experience in many regions suggests this is unpalatable to both consumers and politicians.

In general, there are very few hours in a year (perhaps 100) when utility systems are under stress, and a higher short-run price signal will produce helpful economic curtailment or fuel substitution. Distorting economic reality by failing to inform consumers that serving demand under such circumstances is very costly foregoes that potential benefit and produces enormous waste. Similarly, there are rare occasions when, for example, the cost of serving incremental loads in the short run is very small as a result of hydro or wind systems operating under “spill” conditions, and failing to attract incremental load during those hours causes the permanent loss of an economic opportunity that exists only for a short time.

What this means is that more dynamic, time-varying pricing can send more targeted signals to end users that reflect real-system conditions that may exist only over relatively short periods, but which are difficult to predict. Dynamic and time-varying pricing may also send signals that reflect conditions over the long term, but differentiated in ways that are more granular (in time) than broader conditions captured through the average prices sent through a flat kWh charge more common with traditional meters. Time-varying and dynamic price signals can send both short- and long-term price signals to consumers.

Simply stated, there is a place for dynamic pricing when short-term cost drivers deviate dramatically from long-term conditions, if that pricing can produce a short-term response that does not adversely affect long-term behavior. Short-term cost variability, defined here to reflect variability in costs within the billing period (usually a month), can also reflect long-term or persistent cost conditions, and

encourage sound investments in energy efficiency or load flexibility that are fundamentally driven by persistent long-run cost concerns.

That said, the regulator has more ability to ensure that the price signal sent reflects long-term costs when prices are set administratively for a period of time. The disadvantage of this path is that temporary, limited-term, or even persistent but irregular, short-term scarcity or surplus conditions are never revealed to the end users. Administratively set TOU pricing may address the character of time-varying costs in the long term, but again may fail to address short-term conditions in the short run.

In this paper, we emphasize the importance of getting long-term costs included in the rate design. Given the limitations of conventional meters, we do so largely separate from cost concerns associated with time-variance or scarcity. Nevertheless, we also encourage policymakers and regulators to recognize the special role that dynamic pricing frameworks can play in addressing either short-term scarcity, encouraging greater opportunities for using demand-side resources, and addressing relatively short-term reliability concerns that may not be addressed effectively through administratively determined rates. And as noted elsewhere in this paper, rates set through market mechanisms, and components of rates (e.g., wires charges), can be structured in concert to capture both short- and longer-term objectives for rates.

As noted in the second report on dynamic and time-varying rate design¹² and elsewhere in this report, due consideration should be given to concerns for potential customer confusion over unduly complex rate design. End users, particularly residential and small commercial customers, may be ill-equipped to respond to, and consumers should not, as a general matter, be subjected to complex rate designs that they do not understand and cannot respond to. Regulatory strategies exist, however, that can help address such concerns. Service offerings that allow the customer to, for example, access such services optionally may address these concerns, but this is the subject of the companion global report on dynamic pricing.

This paper is one of a pair of papers that explore the broad range of retail pricing structures for electricity services in use around the world today. It will examine

12 Faruqui et al., 2012.

whether and how the principle of sending long-term pricing signals is put into practice using conventional metering and billing systems. The companion paper on time-varying and dynamic rate design looks at pricing made possible by advanced metering infrastructure – AMI, the so-called “smart” meters and their associated technologies. Together the papers identify a number of approaches to the design of retail electricity prices, examine whether they conform to the general principle, and address a number of other issues germane to the adoption of various pricing regimes.

As we prepare this paper, there are several changes taking place in the power sector that have significant bearing on the choices we make about retail pricing. First, as reflected in the companion report, new technology is enabling utilities and customers to install meter technology that enables price signals that are responsive to then-current market or system conditions, sometimes referred to as “dynamic” pricing. This enables a more responsive demand to then-current system conditions in real time.

Second, today’s lower cost of natural gas and the declining costs of solar technologies have bearing on our notions of long-term costs. Natural gas price trends are impacting the fuel component of longer-term costs, especially in North America. At the same time, solar cost reductions are providing a means to cost-effectively bypass the grid, especially true in areas currently not connected to the existing grid, and in areas with high tail-block rates (the charge per kWh for the most expensive portion of a customer’s usage) and with strong solar resource potential. This may have the advantage of promoting distributed generation and clean technology, but may present certain regulatory challenges and motivate the utilities to more closely align price signals with both short- and long-term utility avoided costs. (An example of utilities aligning short-term price signals with medium- and long-term costs is critical peak pricing, which allows utilities [or system operators] to avoid the need for additional capacity.)

A third potential phenomenon of importance in the longer term is the construction of supply-side resources, particularly certain categories of renewable generation that are less flexible than more traditional supply-side resources that can be more easily dispatched in real time to maintain system balance. A flexible and effective demand response capability is of growing importance to maintain system reliability cost-effectively. Advanced meter infrastructure,

when combined with certain pricing schemes, offers the potential to foster a more effective demand response capability as a critical step toward integrating demand-side resources more directly in the delivery of critical balancing and reliability services that are needed for a system with substantial clean, but less flexible, renewable resources.

A. Structure of the Paper

This first section provides an overview of the goals and objectives of pricing. Section II provides examples of typical electric rate designs found in developed countries, as a way to explain the individual elements of specific rate designs. Section III provides specific examples of progressive utility rates in use by utilities in the United States, Canada, Europe, China, and India. We call these “best practices,” but recognize that without examining every rate implemented by the thousands of electric utilities around the world, this terminology is a bit presumptuous. Finally, Section IV discusses some basic goals for improving rate design to make it more conducive to achievement of clean energy goals. A separate report that provides helpful context for this paper is entitled Regional Power Sector Profiles in the U.S., Europe, India, and China, and helps to explain the current state of the electric utility industry in those regions.

B. Principal Pricing Approaches Examined

This paper provides much greater detail on a subset of issues addressed in previous RAP publications on pricing, specifically those that can be accommodated without advanced metering infrastructure. These include:

- Usage-sensitive pricing based on the long-run incremental cost of new resources, including transmission, distribution, losses, and environmental impacts;
- Higher usage charges, not fixed monthly fees;
- Inclining block residential rate designs;
- Seasonal rate designs to reflect higher winter or summer costs;
- The recovery of pollution-control costs in per-kWh charges;
- Connection charges for new customers that encourage the construction of more energy-efficient buildings; and
- Preferred practices for discounts for low-income consumers.

C. The Division Between “Simple” and “Advanced” Metering

This paper describes options available using conventional meters not connected to AMI systems, which typically require manual meter reading. Included in this category of meters are those that can be pre-programmed to record usage during predefined TOU periods, such as on-peak, off-peak, and shoulder periods. It does not include more advanced meters that record “interval” data in periods of, say, 15 minutes or one hour, for subsequent analysis and assignment to rate periods, if these are connected to AMI systems, but it does include use of such meters if they can be set to record usage in predefined periods and are read manually. Interval metering in which the intervals can be varied easily, which is becoming increasingly more common, falls into the realm of AMI, addressed in the companion paper. It is important to note that all of the rate designs discussed in this paper can be implemented using AMI, but the more complex designs of dynamic pricing generally cannot be implemented with conventional metering.

D. Goals of Retail Pricing

Traditionally, utility pricing is designed to achieve multiple goals. The most commonly cited of these, set forth by James Bonbright in 1961, include:

- i. The related “practical” attributes of simplicity, understandability, public acceptability, and feasibility of application;
- ii. Freedom from controversies as to proper interpretation;
- iii. Effectiveness in yielding total revenue requirements under the fair return standard;
- iv. Revenue stability for the utility from year to year;
- v. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing consumers (compare this with the adage that “the best tax is an old tax”);
- vi. Fairness of the specific rates in the apportionment of total costs of service among the different consumers;
- vii. Avoidance of “undue discrimination” in rate relationships; and,
- viii. Efficiency of the rate classes and rate blocks in discouraging the wasteful use of service while promoting all justified types and amounts of use.

In the half-century since Bonbright’s treatise was first published, some additional objectives have been added to the list. These include reflecting environmental and other non-priced externalities in prices, encouraging customer investment in clean energy resources, such as energy efficiency and renewable energy resources, and ensuring a reasonable cost for essential levels of service for all consumers. Our evaluation of pricing options in this paper will take these issues into consideration along with Bonbright’s long-established eight.

There are some important tensions among all these goals. For example, stability of rates for consumers may work against effectiveness at recovering the revenue requirement if sales or costs change during the time when rates are in effect. With more widespread efforts to implement energy efficiency measures creating the risk for chronic under-recovery of allowed revenues, this has led to development of decoupling mechanisms,¹⁵ which allow rates to change a little bit between rate cases, in order to ensure that the allowed revenue requirement is collected.

Another tension is between rate stability and the desire to differentiate pricing signals over shorter periods to reflect potential changing cost conditions that are precipitated by short-term events. Concern that the principle of rate stability is potentially violated by rate designs that are so differentiated can be addressed by making the pricing predictable or the participation voluntary.

Another point of tension is the emphasis on revenue and earnings stability. In the face of the fluctuating market circumstances, stable rates, as noted earlier, could lead to earnings instability. Stable revenue is appropriately emphasized in relation to stable costs (as with capital-intensive assets). However, stable earnings may at times be better matched with revenues that are permitted to vary with unstable costs.

15 Decoupling, as used in this paper, is an adjustable price mechanism that breaks the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. For more information, see Lazar et al, 2011.

E. Types of Utilities

There are many types of utilities, but they generally fall into two categories of service and two categories of ownership.

Vertically integrated utilities – Provide bundled power supply, transmission, and distribution facilities; this group may include some that acquire all of their power supply from one or more outside suppliers, but provide customers with a complete product.

Distribution-only utilities – Provide only unbundled delivery service for electricity and leave the electricity supply function to a competitive market or to a single default supplier. These are often referred to as “restructured” or “deregulated” markets.¹⁶

Vertically integrated and distribution-only utilities may be either for-profit commercial entities, owned by investors; agencies or companies owned by local, regional, or national governments; or cooperatives owned by consumer members.¹⁷ There are variations along both the integration and the ownership dimensions.¹⁸

F. Different Ways of Measuring Cost

There are important economic terms that are used in electricity pricing, and a general understanding of these terms is crucial to understanding pricing alternatives.

Embedded cost – The accounting (or “historic”) costs of resources required to serve customers, typically including production, transmission, distribution, and overhead costs. Because of inflation, amortization of past investments

through depreciation, and changes in regulatory requirements, the embedded costs for many utilities are often significantly lower than the cost of creating a similar system today, if that is even possible. For regulated utilities, embedded costs – along with a fair return on invested capital – normally form the basis of the capital portion of the revenue requirement.

Long-run marginal or long-run incremental cost – The total cost of building and operating new facilities and otherwise providing an increment of service at current costs, including production, transmission, distribution, and overhead costs.¹⁹ Because utility costs have increased, in many cases faster than inflation, and embedded technologies (e.g., unscrubbed coal, 20th century nuclear technology, and above-ground distribution lines) may no longer be acceptable, LRMCs tend to be significantly higher than embedded costs, at least for efficient systems in developed economies. In some cases, technologic innovation may be sufficient to reduce the long-run cost below the embedded cost. The term Total System Long-Run Incremental Cost (TSLRIC) is sometimes used to describe the cost of building and operating a utility system from the ground up at today’s costs.

Short-run marginal cost – The variable costs incurred to operate the existing system to serve the last or next increment of load, including fuel, purchased power, lost export sales, environmental charges, variable maintenance, and other costs that vary with usage in the short term. Because this definition does not include recovery of major categories of fixed costs (e.g., wires investment and capital portions of generation), annual average SRMCs are often

16 The term “liberalized” is sometimes used in the United Kingdom and other countries to describe restructured markets.

17 There are important differences in the extent to which a utility owned by a government entity can be considered consumer-owned. At one extreme, some municipal utilities are controlled by boards elected by voters in their service territory (often a single municipality), so the residential consumers have reasonably close control over the utility. In other situations, the utility is controlled by a broader governmental entity, as is the case for the Long Island Power Authority (owned and controlled by the state of New York, but providing power in just two counties of that state) or the Tennessee Valley Authority (federally owned and

controlled, providing wholesale power in parts of seven states). Government utilities may be further disconnected from consumer control if the government lacks transparency or democratic legitimacy.

18 For a more detailed discussion of utility business structure, see Chapter 4 of *Electricity Regulation in the U.S.: A Guide*. Regulatory Assistance Project. (2011, March). See www.raponline.org/document/download/id/645

19 In the jargon of economics, the LRMC of production is the cost incurred to serve a small, almost infinitesimal increment of demand when all factors of production (labor, capital, and other inputs such as fuel and materials) are variable. The optimal mix of the factors will yield the minimum LRMC.

lower than the bundled average LRMCs of service. Whether they are below or above will depend on the specific generation resource mix and fuel prices.²⁰

In a few cases, particularly where utilities have insufficient modern capacity, they may use generators with high operating costs to augment more efficient lower-cost resources; in this situation, short-run costs may actually exceed long-run costs. Short-run costs will also exceed long-run costs when supply conditions tighten and only the highest cost (generally peaking) resources are available to meet load. SRMC may be higher or lower than embedded costs; the former looks at the increment of costs to serve an increment of load, which may involve high-cost fuel and inefficient power plants, whereas the latter measures total average costs, including older and cheaper power plants used to provide the majority of service.

G. The Process of Retail Pricing

The setting of electricity prices for a fully regulated utility generally follows a formal legal process that includes determining the revenue requirement based largely on embedded cost considerations. This involves determining the cost of providing service, including capital costs, allocating costs among classes, and designing prices within classes to recover the allocated revenue requirement.^{21, 22} For restructured utilities, the process of setting distribution prices is generally similar, but prices for competitive services are set by the marketplace.

The first step in determining prices is to calculate the total allowed revenue for the utility, known as the revenue requirement. In most jurisdictions, it is computed so as to provide the utility a reasonable opportunity to recover

(1) a fair rate of return on the unrecovered portions of depreciated plant, and (2) its expected operating expenses, including depreciation. (In a few jurisdictions, however, the investment is allowed to be restated at fair market value; in these jurisdictions, the allowed rate of return is typically lower than it is in the “depreciated plant” jurisdictions.) This approach is generally applied to all monopoly services: distribution, customer services, transmission,²³ and (where it is part of the regulated service) power supply.

The second step is the allocation of costs between customer classes (e.g., residential, commercial, industrial). The various types of costs (e.g., production of power, transmission and distribution [T&D], administrative costs, metering, and billing) are allocated separately based on an appropriate choice from a variety of factors, including numbers of customers, various measures of the peak demand of each class, and the energy usage of each class. There are literally dozens of different methods for allocation of some major cost factors, often making allocation one of the most contested issues before utility regulators when revisiting rate design. Some methods use embedded costs, whereas others use various concepts of LRMCs described earlier. Because allocation concerns the fairness among classes of customers, there is no single optimal way to allocate costs.²⁴

The third step is to design prices, or rates, for each class of consumers that will yield the allocated costs based on the expected quantities of goods and services sold (the “billing determinants”). Since a central purpose of rate design is to give efficient price signals, while determining the revenue requirement allocation of costs involves the fairness in total revenues and their corresponding spread among classes, different approaches may be appropriate

20 Again, in economics, the SRMC of production is the cost incurred to serve a small, almost infinitesimal increment of demand when at least one factor of production (typically capital) is fixed. The SRMC will be minimized when the mix of inputs is optimized, given this constraint.

21 The process as a whole should address multiple objectives, including encouraging efficient consumer practices discussed earlier. Well-designed rates will cause customers to manage their usage so as to minimize their costs, which will likewise reduce the system’s costs of serving them.

22 The process for setting retail rates is discussed in detail in Chapter 9 of *Electricity Regulation in the U.S.*, and is only briefly summarized here. For more information see: Lazar, 2011a. 23 In most of the United States, transmission rates are set by the Federal Energy Regulatory Commission, whereas other rate components are set by state regulators.

23 Lazar, 2011b.

for setting prices than for the other steps. In fact, it is quite common for regulators to use an embedded-cost method for determining the revenue requirement, but a marginal cost method to design prices.

There are a variety of other issues that regulators address in setting prices. These include low-income and economic development discounts, the recovery of so-called “stranded costs,” charges for connection or termination of service, and charges for extending utility lines to new areas to serve

new customers. And regulators determine whether to use inclining block rates, declining block rates, TOU rates, and the shares of demand and energy charges for those classes in which the differentiation of these charges makes economic sense. All of these may affect the recovery of the revenue requirement and change the amount charged per unit of service. Some of these issues are addressed separately below.

3. Elements of Traditional Rate Designs

A. Customer (Monthly Service) Charges

Retail electric rates typically include a monthly fixed charge, variously called a customer charge, basic charge, standing charge, or service availability charge.²⁵ This normally covers at least the costs of metering and billing and often other customer service costs (e.g., accounting, responding to customer queries). Some utilities include a portion of distribution costs, which may be limited to facilities that serve only one to a few dozen customers (e.g., service drops, secondary lines, and line transformers) or even portions of the primary distribution system that serve hundreds or thousands of customers.²⁶

B. Energy Charges

Most retail rates also include one or more charges for the amount of energy (kWh) consumed during the billing period. These may be structured in one or several blocks of kWh, which may be priced in various ways. For example, one block might represent kWh consumed up to the first 500 kWh consumed in the billing period, with a second block representing all kWh consumed beyond the first block. The pricing of such blocks of energy consumption may be treated in several different ways, including inclining block pricing (incremental usage carries a higher price) or declining block pricing (incremental usage carries a lower price). Some points to note about each include:

- Inclining block rates are common worldwide and are based on several different theories, including:
 - Higher residential usage is associated with space conditioning, which is highly peak-oriented;
 - Small users may be deemed to each get an allocation of low-cost energy from low-cost resources such as hydro or coal; and
 - All customers should get enough energy to meet essential needs at an affordable price, even if it is

- subsidized (also called “lifeline” rates)
- Declining block rates have been popular with many utilities, based on such factors as the following assumptions:²⁷
 - Higher volume consumers are cheaper to serve, due to volumetric economies of scale; and
 - The customer charge does not collect all the distribution costs on a per-customer basis, so it is appropriate to recover the rest of those costs through a higher priced initial (low usage) block.

Other factors commonly employed to differentiate the pricing of energy consumption include the following:

- Seasonal pricing, in which prices are different for energy used during different months, such as one rate for usage in May to September and another rate for October to April, to reflect differing energy costs and/or contribution to peak loads and need for capacity.
- TOU pricing, in which prices are different for energy used during different time periods, such as one rate for noon to 6 PM weekdays, and another for all other hours, driven by the same factors as seasonal pricing. Fixed period TOU pricing does not require AMI.
- Different rate components, particularly where those are set by separate mechanisms. For example, transmission rates may be set annually by a national regulator (as in much of the United States) or a

25 This discussion assumes that rates are based on monthly billing. Some utilities bill less frequently.

26 The further the equipment is removed from the customer, and the more customers using a piece of equipment, the weaker the argument for recovering the costs through the customer charge.

27 Declining block rates are also usually based on the assumption that only embedded costs matter, or the belief that the marginal cost of energy is less than embedded costs. As discussed below, declining block rates are usually inappropriate.

regional supplier; distribution costs may be set every few years by a local authority on the petition of the utility, whereas charges for purchased power may be set monthly based on current market rates.

C. Demand Charges

Many electric tariffs²⁸ for large customers include a demand charge, based on the customer's maximum usage (in kVA or kW) in an hour (or shorter period) during the month. In some tariffs, demand charges vary by month or by TOU.²⁹ Some tariffs have more than one demand charge: one based on system coincident peak demand to cover production and transmission costs and a second charge based on non-coincident peak demand to cover distribution costs.³⁰ Certain types of traditional meters can measure the customer's non-coincident peak load during the billing period in addition to the customer's energy consumption during that period.

The rationale for demand charges is twofold: (1) the customer's own peak drives the sizing and costs of some local equipment (presumably further upstream for large industrial customers than for residential customers), and (2) individual customer peak loads, especially coincident peak loads, are correlated with peak load on system, generation needs, regional substations, and transmission.

Prior to the development of TOU metering, various forms of demand charges were the only way to reflect the customer's usage pattern in rate design. Demand charges result in a pricing structure that encourages customers to have consistently high energy use throughout the billing period, that is a high load factor (kWh use divided by kW maximum load for all hours in the period), because demand charges remove some of the costs from the energy charge resulting in a lower per unit energy price. Such customers were generally considered to be efficiently utilizing the utility's assets, by putting a steady demand on facilities night and day, throughout the month.³¹

Three considerations make demand charges less valuable than once thought and, in some situations, even counterproductive. They track cost causation very poorly, creating poor incentives; they are hard to understand; and they "use up" (collect) a portion of the "revenue requirements" that could otherwise be used to bring energy charges closer to full long-run marginal social cost.

First, because demand charges based on conventional

meters are levied on the customer's maximum (non-coincident) load, whenever that occurs, demand charges encourage each customer to shift loads off its peak. That shift may or may not reduce system costs, because the customer's peak may or may not be coincident with the system peak. Indeed, shifting load may increase total energy use, and the customer may be shifting load off its peak but onto higher-load, higher-cost hours for the system.

For example, an industrial plant that would normally hit its maximum demand at the beginning of the first shift at 7 AM as it starts up all its equipment may be encouraged by a demand charge to delay some of that start-up to 9 AM, when stores and offices are opening and commercial loads are ramping up. The result may be higher loads on the feeder, substations, and subtransmission serving that area. In this example, the shift is unlikely to reduce the system peak load, and is more likely to increase peak load or at least increase loss-of-load probability. Thus, actual distribution, transmission, and generation capacity costs may all be increased by demand charges.

Alternatively, the customer in our example could choose to start some equipment at 6 AM, reducing its billing demand but increasing energy use, as its equipment would be turned on for an additional, unnecessary hour.

Second, many commercial customers, other than the very largest, tend to have difficulty understanding the

28 A tariff is an official document setting out the pricing structure for a given class of customers, usually including the various terms and conditions of service that apply and who qualifies for that class of service.

29 For example, the demand charges may be \$10/kW-month for the customer's maximum hourly usage in the peak period, plus \$2/kW-month for the difference between the customer's maximum off-peak demand and its maximum on-peak demand.

30 A customer's system coincident peak is that customer's load during the specific time (hour or smaller increment of time) when the system had its peak load. A customer's class coincident peak is that customer's load during the specific time when the customer's own class had its peak load. A customer's non-coincident peak is that customer's highest load during the billing period regardless of when it occurred.

31 Including a demand ratchet along with a demand charge, as discussed below, creates a similar incentive for customers to have consistent loads across seasons, as well.

causes of their billing demand. With traditional demand metering, the utility only knows the maximum load since the last reading, not when it occurred or what combination of equipment contributed to it. Hence, customers cannot determine what caused their billing demand, or why it is particularly high in one month or another. Only large sophisticated customers, with extensive sub-metering of major equipment, are likely to be able to understand the drivers of their billing demands.³²

Third, in jurisdictions that establish rates based on an underlying cost-of-service, or “revenue requirement,” the demand charge can detract from the establishment of clearer usage price signals that may be most effectively placed in a usage or kWh charge, especially at the tail usage block.

D. Demand Ratchets

Some tariffs set the billing demand at the higher of (1) the current month’s measured demand, and (2) a fraction (typically 80 or 90 percent, but sometimes as much as 100 percent) of the customer’s highest measured demand in the previous year, or in the past peak seasons. This type of pricing is referred to as a “demand ratchet.”

These ratcheted demand charges stabilize utility cash flow, and make the customer’s annual maximum load (or its maximum load in the designated peak months) even more critical to its overall cost of power. Unfortunately the customer’s maximum demand (annual, seasonal, or monthly) rarely causes the costs collected by the demand

charge, so the ratchet only serves to further distract customer attention from the more important long-term cost driver, demand for energy. Demand ratchets also dilute the customer’s incentive to conserve, as energy efficiency measures the customer may install will have no effect on the demand charge until a full year has passed.

E. Load-Factor Rates

Some tariffs use the measured demand to modify the energy charges, instead of or in addition to imposing a separate demand charge. These charges may charge, for example:

- 4¢/kWh for energy up to 200 times the monthly billing demand;
- 3¢/kWh for energy from 201 to 400 times the monthly billing demand; and
- 2¢/kWh for energy above 400 times the monthly billing demand.

These load-factor tariffs have many of the same problems as simple demand rates and demand ratchets, and are even harder for customers to understand.

32 Modern interval metering allows the utility to provide the time of the billing demand, and load levels at other times, but not the cause of the high-demand hour. If the customer has an interval meter, recovering the demand revenues through TOU energy rates may provide superior price signals.

4. The Principles of Rate Design and Some Issues Arising from Them

In this and the sections that follow, our analyses of the form and effect of different types of rate design will be guided by five guiding principles. They are an amalgam of the core Bonbright principles, modified to reflect the world's greater understanding today of the environmental and social consequences of electricity production and use.

First and foremost, prices ideally should be forward looking and reflect LRMCs for future resources, including production, transmission, distribution, administrative costs, and environmental costs. In most parts of the world, the existing per-kWh rates fall short of this standard. Consumers make decisions based on energy costs that affect their usage in the long run (e.g., selecting more efficient equipment, increasing the efficiency of buildings) and in the short-run (turning off lights, adjustment of thermostats), but in neither case do the prices accurately capture the underlying costs (including external costs) to serve those needs.

Second, a rate design must be simple enough for the customer to understand. Different types of customers can comprehend different levels of complexity in rate design. The level of sophistication generally increases with the customers' consumption levels and the amounts they spend for electricity. Having relatively simple default pricing, with more complex options added on as necessary for larger customers, allows for that flexibility.

Third, prices should concentrate on the energy or usage-sensitive components of service if they are to encourage consideration of economic alternatives to grid-supplied electricity, for example, energy efficiency and customer-sited energy production. Energy usage drives the vast majority of the costs of most utilities, including fuel, purchased power, investments in generation, and the cost of transmission from remote plants. Although concentrating revenue collection in fixed charges (such as the monthly service charge and demand charges tied to maximum usage) sta-

bilizes revenues for utilities, these types of rate forms have several very serious drawbacks. First, under such rates, consumers see only a small change in their bills if their usage changes, discouraging investment in energy efficiency and on-site energy options like solar. Second, low-usage customers, many of whom are low-income, face disproportionately higher costs per kWh and therefore higher bills. And last, apartment dwellers and people in tightly-packed housing developments, for whom distribution costs per customer are lower, pay a disproportionate share of system costs. Perhaps most important, however, is that the retail price for incremental usage can no longer fully reflect the incremental cost of meeting incremental power needs. There are better ways to provide for utility revenue and earnings stability and also send meaningful signals to customers.

Fourth, if utility system costs vary by season or time of day, or if a significant portion of utility investment is driven primarily by load in particular months or particular hours of the day, efficient pricing should reflect these cost drivers. But it is crucial to consider this on a total system basis – in many cases, shifting loads from on-peak periods to off-peak periods may cause environmental harm if it means additional reliance on coal-fired generation. Even though fuel prices may be lower at such times, the total societal cost may very well be significantly higher than during on-peak hours. Every system differs in the mix and environmental attributes of its supply portfolio, and thus each system's time-varying costs also vary. These are matters for empirical analysis.

As noted earlier, not all costs caused by energy use are included in the utility revenue requirement. The production of electric energy results in a wide range of environmental and other non- or undervalued effects, including, among others:

- Emissions of carbon dioxide and toxics such as SO₂, NO_x, particulates, toxic coal ash, and other forms

of air pollution that come from the burning of fossil fuels;

- Water and land pollution, such as mining equipment fuel consumption, mining waste, or hydrofracturing fluid and other chemicals, resulting from the extraction of fossil fuels from the earth;
- The risks associated with the construction and operation of nuclear power plants, including nuclear waste;
- Thermal pollution of rivers and lakes;
- Entrainment and impingement of aquatic species in steam-plant cooling systems;
- Flooding of reservoirs for hydroelectric plants, which changes habitats and ecosystems; and
- Fragmentation of habitat and introduction of invasive species along transmission rights of way.

Retail electric prices generally do not reflect these effects; but some emissions are at least partially internalized, such as SO₂ in the United States and CO₂ in New England, California, and Europe. If we want consumers to see the total economic cost of their energy consumption (and thus the real value of alternatives to that consumption), then rate design must emphasize the true levels and sources of the cost, that is, include them in per-kWh prices. There are costs of environmental externalities that are not paid by utilities, and there are cost changes over time that may not be reflected in the utility's current revenue requirement. Both of these factors tend to justify pricing that has higher-than-average prices for incremental consumption, because it is at the margin where changes in behavior and usage patterns can occur. This justifies use of inclining block rates and minimization of fixed charges on bills so that the variable price elements can more fully reflect incremental costs.

5. Rate Design Basics and Examples

This section describes a variety of rate design options available to utilities that have not installed AMI and offers general observations about their efficacy. In Section 11, “Examples of Global Best Practices,” we take a look at a number of tariffs from around the world and explain how, through the application of these general principles of rate design, they succeed in improving the efficiency, and reducing the environmental consequences, of electricity production and consumption.

A. Integrated vs. Restructured Utilities

Vertically integrated utilities often charge consumers for power supply, transmission, and distribution service in a single pricing schedule, approved by a single government regulator or governing board. Sometimes these rates are “unbundled” into separate price elements for power supply and delivery.

Restructured electric distribution utilities may provide only distribution service, but may also serve as the conduit for a default power supplier for those consumers who do not select a competitive supplier. In most parts of the world, even where markets have been restructured, small residential and small commercial consumers often take service from a default supplier.

In some markets like Texas and the United Kingdom (described subsequently), the distribution service can disappear entirely from the customer bill as it gets folded into the services provided by competitive retail providers. In these circumstances, rate design pertains to the wholesale charges for wires services charged by the distribution company to the competitive providers. Although these charges may be masked from retail customers, they may also influence retail pricing structures that are applied by the competitive retail providers.

Although the majority of this paper addresses integrated utilities, this section will demonstrate how a restructured electricity pricing framework might look, given separate

pricing for both delivery and power supply.

We begin by presenting three simple bundled tariffs for residential, small commercial, and large commercial usage. We then proceed to examples of more complex rates that can be supported by conventional metering. Last, we turn to distribution-only and power supply-only rates of restructured utilities.

B. Basic Tariff Designs

A basic residential tariff typically includes only a customer charge (sometimes called a basic charge, fixed charge, or standing charge) and an energy charge, with no differentiation by usage block, season, or time of day. The customer charge is normally designed to recover metering and billing costs, but may include some distribution costs; all other costs are recovered in the energy charge.

Figure 1

Simple Residential Tariff	
Rate Element	Price
Customer Charge \$/month	\$5.00
Energy Charge \$/kWh	\$0.10

Prices for the lowest-volume commercial consumers typically look a lot like those for residential consumers, except they are usually a little higher. This reflects the fact that their usage is concentrated during the higher-cost business week when utility peak demands usually occur. Also, because their meters often take longer to read, and the costs of setting up the billing program are spread across fewer customers, the monthly customer charges are typically higher for these customers.

33 In some places, the utility is the default supplier, using affiliate resources or market procurements.

Figure 2

Simple Small Commercial Tariff	
Rate Element	Price
Customer Charge \$/month	\$10.00
Energy Charge \$/kWh	\$0.11

Larger commercial customers, such as supermarkets, multi-story office buildings, and large retail stores, typically have what is called a “two-part” tariff, consisting of separate energy and demand charges. In most cases, the demand charge is applied to the customer’s non-coincident peak demand, that is, the highest period of the customer’s usage, regardless of whether it occurs at the time of the system peak.

Figure 3

Basic Tariff For Large Commercial Customer	
Rate Element	Price
Customer Charge \$/month	\$20.00
Demand Charge \$/kW/month	\$10.00
Energy Charge \$/kWh	\$0.08

Because these customers pay part of their usage costs through a demand charge, the per-kWh rate is a little bit lower than would be the all-in energy charge. The total cost per kWh, including the demand charge (converted into a per-kWh charge, given the customer class’s average usage and load factor), is typically about the same or a little lower than the average of residential rates, reflecting some economies of scale in serving larger customers.

C. Beyond Basic Usage Rates for Integrated Utilities

Usage rates for vertically integrated utilities typically consist of a monthly fixed charge, and one or more usage blocks or time periods. For larger customers, a demand charge, based on the peak usage during the billing period, may also be included.

i. Residential

The residential (domestic) customer class has the most similarity between consumers. Although there are large and

small homes in any service territory, utilities sometimes classify residential consumers into a few more well-defined groups. In some jurisdictions, this may include:

- a “lifeline tariff” for income-eligible poor households;
- a separate tariff for customers heating or cooling with electricity, or using electricity for water heating; and
- housing-type subclasses, such as tariffs for apartment flats, mobile homes, or other housing types, reflecting load shape, cost of connection, and other considerations.

Not every rate schedule will have the same rate elements. The subsections following provide a general overview of the features of residential tariffs.

1. Monthly Fixed Charge

In many jurisdictions, the monthly fixed charge covers only metering and billing services. Some utilities in some countries are allowed by their regulator to include a portion of the distribution system cost in the fixed charge. All remaining costs of electricity distribution and supply are recovered in usage rates.

a. Customer-Specific Facilities

A monthly customer charge for customer-specific facilities is quite common. This may include the cost of the meter and service drop. In addition, because meter reading and billing are incurred on a per-customer basis, these are often included in the monthly fixed charge. A typical monthly fixed charge computed on this basis may range from \$1.00 to \$7.00 per month, depending on the level of expenses incurred. Where higher customer charges are computed, they typically include recovery of distribution system components, such as transformers and overhead and underground lines.

b. Shared Facilities

Shared facilities, including distribution lines and line transformers, are most commonly recovered through usage charges. Some analysts designate a portion of these costs as

34 This is relatively unusual outside of the United States, but in the United States, an effort by utilities to recover distribution costs in fixed monthly charges has been accepted by some regulators. Many self-regulated rural cooperative utilities also follow this practice.

customer-related and include them in the customer charge.

2. Block Rate Design

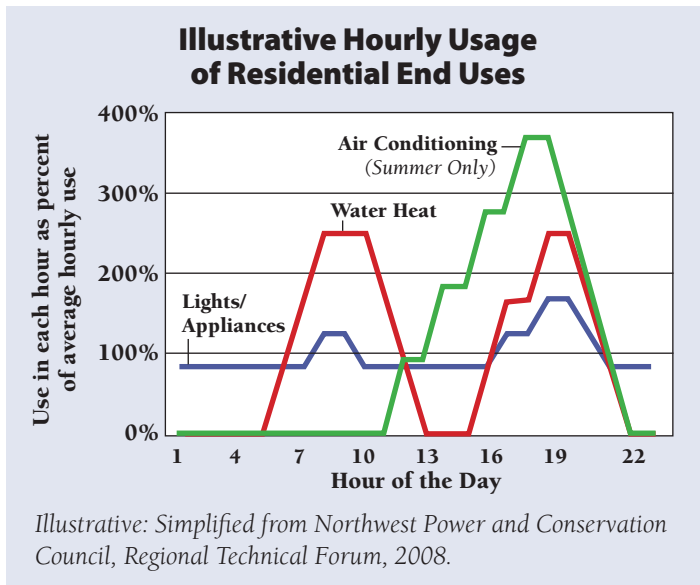
Some utilities have a single volumetric rate per kWh that is applied to all usage, regardless of level of usage. These are called “flat” rates. Others have a price that increases or decreases with increased consumption. These are referred to as inclining block and declining block rates respectively, and are used to address different policy objectives. There are several different theories underlying the development of block rates.

a. Load-Shape Considerations

In general, residential load factor declines as usage increases, because peak-oriented air conditioning (or space heating) becomes the dominant usage for most larger residential users. For this reason, many utilities have established higher prices for higher usage blocks – to recognize that water heating or space conditioning is not as steady through the day and year as basic lighting and appliance usage, and that these end uses require additional investment in extra capacity that is only used at peak periods.

The graphic below, which is illustrative only, gives a rough sense of when during the day different types of residential loads occur, expressed as a percentage of the average hourly usage through the day; note that air conditioning is a seasonal usage, occurring only in the hotter months.

Figure 4



Data of this type vary by utility, region, country, and many other factors. The point is that air conditioning is a peak-oriented load, and that lights and appliances loads are far more uniform and predictable. Although water heating usage occurs year-round, it is concentrated in the morning and evening, and contributes significantly to most utility system peak demands (unless regulated by timers or utility remote control).

b. Resource-Based

Some utilities have access to a limited supply of low-cost energy. This may be power from hydroelectric dams, built in part for water supply, navigation, flood control, or other purposes. It may be power from older, largely depreciated coal plants, or another low-cost source of power. When this occurs, a utility may offer each consumer an initial block, based on an equitable allocation of the limited low-cost resource.

Figure 5

Utility Resource Supply and Cost		
Resource	Percent of Total Supply	Cost/kWh
Hydro	20%	\$0.02
Coal	50%	\$0.05
Natural Gas	30%	\$0.08

c. Vintage

Vintage rates are relatively unusual, but are designed to assign older power resources to specific groups of customers, or to all customers in limited quantities. They have been used where one particular class or subclass has grown rapidly, and a decision was made to assign the cost of new resources to the growing class or subclass. These

Figure 6

	Usage Not In Excess of Amount Used Before 2000	Usage In Excess of Amount Used Before 2000
Customer Charge	\$10.00/month	\$10.00/month
Demand Charge	\$10/kW/month	\$10/kW/month
Energy Charge	\$0.05	\$0.10

may take the form of inclining block rates or they may take the form of higher rates for new customers than are paid by historical customers.

For customers using no more power than they did in the “base” period, this is a flat rate design; for those whose usage has increased, it is an inclining block rate. For those initially connected to the system after the “base period,” it is a flat rate at a higher level than vintage customers pay.

d. Revenue Requirement-Constrained

The most common type of inclining block rate design is one that is based on economic efficiency considerations under a constrained revenue requirement. If LRMCs are higher than embedded costs and the utility revenue requirement is limited to recovery of embedded costs, many regulators will “underprice” an initial block of usage (or discount the monthly fixed charge) in order to more accurately reflect LRMCs in the end-block rate for incremental service. This has the effect of better aligning incremental prices with incremental usage.

A typical residential inclining block rate design, based on any of the principles above, might have the following rate form:

Figure 7

Residential Inclining Block Rate	
Rate Element	Price
Customer Charge \$/month	\$5.00
First 500 kWh/Month	\$0.08
Next 500 kWh/Month	\$0.11
Over 1,000 kWh/Month	\$0.14

Inclining block rates have the effect of combining multiple rate design goals into a simple to understand structure. First, as discussed previously, there are many cost justifications for inclining block pricing, from allocation of a low-cost resource to recognition that load factor declines as usage increases. Second, most customers with loads that vary by season will use more during the high-cost season (summer cooling or winter heating) and rise into the next block, making an inclining rate function as a seasonal

rate for such customers. Inclining block rates provide lower bills to the majority of (but not all) low-income consumers, the majority of whom have usage that is lower than average. (Of course, low-income customers that rely more on electricity for heating or cooling during the high-cost season may face higher bills than average residential customers.)

For these reasons, inclining block rates have been implemented in many parts of the world and have received high levels of consumer acceptance. From a clean energy perspective, inclining block rates can do a good job pricing incremental usage at a level reflecting the cost of new resources plus the environmental costs associated with electricity usage.

Appendix A shows how an illustrative inclining block rate can be expected to lead to about an 8-percent reduction in residential consumption; that estimate will vary significantly from utility to utility and region to region.

The opposite approach is known as straight fixed/variable (SFV) rate design, a term taken from a rate design originally developed for natural gas pipeline long-term contracts. An SFV rate collects all costs except those that vary in the short run in a fixed monthly charge, running to perhaps \$40/month or more. The price per kWh is therefore relatively low, because it reflects only those costs that can be immediately avoided by the utility if sales decline. It doesn’t give consumers any ability to avoid the long-term capacity costs that their continued consumption causes. Appendix A shows that this type of rate design could lead to about an 8-percent increase in residential consumption.

3. Fixed Period Time-of-Use

A fixed period TOU rate is one in which customers know in advance that prices will be higher during on-peak periods. This may be as simple as a seasonal summer/non-summer rate differential, or more complex with on-peak, mid-peak, and off-peak periods. A seasonal rate can be implemented without any special meters; a TOU rate requires (at a minimum) meters that can register that usage.

An example of residential fixed-period TOU rate might have the following form:

Figure 8

Residential Fixed Period TOU Rate		
Rate Element	Summer Months	Non-Summer Months
Customer Charge	\$5.00/month	\$5.00/month
On-Peak Noon – 6 PM	\$0.15/kWh	\$0.10/kWh
Mid-Peak All Other Hours	\$0.10/kWh	\$0.08/kWh
Off-Peak 10 PM – 7 AM	\$0.07/kWh	\$0.06/kWh

4. Combining Inclining Blocks with Time-of-Use Rates

It is relatively easy to combine an inclining block rate with a fixed period TOU rate design, and this has been done in California and other places. An inclining block rate can be viewed as a “discount” from the end-block price for a limited amount of usage. The TOU rate can be structured to provide a clearly defined TOU rate, plus a defined discount for a first block of usage, no matter when the usage occurs. The three-block, non-TOU inclining rate shown in Figure 8, with a block of 500 kWh at \$0.08/kWh, followed by 500 kWh at \$0.11/kWh, provides a \$15.00 savings in the first 500 kWh compared with the second block. Turning this concept into an inclining block TOU rate would look like this:

Figure 9

Residential Seasonal TOU Rate with Inclining Blocks		
Rate Element	Non-Summer Months	Summer Months
Customer Charge	\$5.00/month	\$5.00/month
On-Peak Noon – 6 PM	\$0.10/kWh	\$0.15/kWh
Mid-Peak All Other Hours	\$0.08/kWh	\$0.10/kWh
Off-Peak 10 PM – 7 AM	\$0.06/kWh	\$0.07/kWh
Less discount on first 500 kWh:		\$0.03/kWh

With this rate design, customers will see a TOU price for all usage and receive the same economic benefit as an inclining block rate. The discount on the first 500 kWh applies regardless of time of day; a customer with 100-percent off-peak usage would receive a higher percentage benefit than one with predominantly on-

peak usage. This is about the most complex residential rate design likely to be implemented with conventional TOU metering and billing systems.

5. Prepayment

Many utilities have experimented with prepaid electricity service. In most cases, this is an alternative to meter reading and billing and, for very small users, those costs can amount to as much as the cost of the electricity supply, so it can be a significant money savings. In South Africa, prepayment was an essential element of extending affordable service to slums and shanties that had no electricity prior to 1990. Prepayment is universal for groceries, for petroleum fuel, and for most other commodities.

Low-income advocates in developed countries, however, often object to prepayment for many important reasons. First, it can cause consumers to suddenly be without electricity and without any means to restore service; advance notice of the possibility of disconnection and a ready means to restore service are customer protections available under traditional metered service. Second, it often treats low-income consumers as second-class citizens, while more affluent customers receive traditional service

with payment due after service is taken. Because the utility receives the funds before providing service, and has no risk of uncollectible bills, prepayment should be a lower-cost service for consumers.

Prepayment meters include “chip” driven systems, where a purchased prepayment card with a computer chip is inserted, and digital systems, where a code is received by the customer when they make payments and entered by the consumer into the meter, much like a prepaid cellular phone recharge card. Both types display the remaining available electricity. It is feasible to incorporate block rate design, seasonal rate design, and even TOU rate design with modern prepayment meters.

The tariff in Figure 10 reflects a discount for prepayment.

Figure 10

Example of a Prepayment Tariff Compared To Billed Tariff		
Rate Element	Prepayment	Billed After Usage
Customer Charge	\$1.00	\$5.00
First 200 kWh/month	\$0.10	\$0.11
Over 200 kWh/month	\$0.12	\$0.13

6. Low-Income Rate Programs

Low-income consumers generally use less electricity than consumers with average and higher incomes, simply because more affluent consumers have more energy-consuming appliances. Therefore, inclining block rate designs and rate designs with zero or minimal monthly customer charges are not only cost-based, but also generally favorable to low-income consumers.

In addition, low-income consumers generally live in less efficient structures and use less efficient appliances. For this reason, it is important to note that targeted energy efficiency programs, such as building weatherization and appliance replacements, can be favorable to low-income consumers. But small incentive payments, which may encourage a more affluent consumer to choose a better new refrigerator or air conditioner when they are buying a new one anyway, will not influence low-income consumers who are seldom in the position to buy new appliances.

Utilities in many countries provide discounts for low-income consumers. These can be explicit discounts based on income qualifications (common in the United States) or a separate tariff that is only available to very small users of power, nearly all of whom are low-income users (Indonesia, South Africa).

There are many types of low-income discounts. Some low-income rates provide a discount or waiver of the customer charge; this preserves the price signal of the rate blocks. Some provide a discount only on the first block of usage, leaving a second block equal to that paid by other customers. Some provide a discount on all rate elements.

Figure 11 is an example of low-income rate discount.

Figure 11

Residential and Low-Income Residential Rate		
Rate Element	Prepayment	Billed After Usage
Customer Charge	\$5.00	\$2.50
First 500 kWh	\$0.05/kWh	\$0.025
Excess Usage	\$0.01/kWh	\$0.05

7. Dynamic Pricing

Dynamic pricing means electricity prices that change as power market or system conditions change. The category includes critical peak pricing, peak-time rebates, real-time prices, and demand-response rates. These types of rates require advanced metering and significant consumer education. Although most commonly applied to larger commercial and industrial customers, they are increasingly considered for residential consumers, given that the cost of advanced metering for smaller customers is falling and that the residential class typically comprises roughly 40 to 60 percent of a utility’s total load. They are discussed in the companion publication to this paper, Time-Varying and Dynamic Rate Design.

D. Residential Pricing for Distribution Utilities

The previous section described bundled service provided by vertically integrated utilities. This section looks at the separate delivery and power supply charges that typically exist when utilities provide distribution service, and competitive power suppliers provide the actual electricity.

Distribution-only residential rates typically include a customer charge and one or more energy charges. Figure 12 provides an example of a residential distribution charge

Figure 12

Residential Electric Distribution Tariff <i>(see below for supply pricing)</i>	
Customer Charge	\$5.00/month
Distribution Charge	3.5¢/kWh
Transmission Charge	1.5¢/kWh

with both a customer and an energy charge.

The examples here are for residential distribution tariffs; however, where utilities are restructured and competitive power supply options are available, there will also be distribution tariffs for general service customers, with similar customer and demand charges for integrated service, as described previously.

E. Power Supply-Only Rates

Where rates are unbundled into separate distribution and power components, or where utilities have been restructured and these charges come from different companies, the prices for power supply can take many different forms. Where there are many competitive suppliers, as in the United Kingdom and Texas, there can be dozens of different options available. We will address only a couple of these.

Figure 13 is an example of a power supply-only rate

Figure 13

Standard Offer Service For Power Supply			
Class	April – September	October – March	(Annual Average)
Residential	7.0¢/kWh	6.0¢/kWh	6.50¢/kWh
Commercial	7.5¢/kWh	6.5¢/kWh	7.0¢/kWh

for “standard offer” (default) service (with the distribution charges not reflected):

In this example, the commercial prices are higher, because the supplier has determined that commercial use is more concentrated during peak periods, while residential use includes more night and weekend consumption.

Sometimes competitive power suppliers offer prices or price options that are fixed (guaranteed) for a period of time, possibly for more than one year. This may reflect the vendor’s own power portfolio, which may be a fixed-price portfolio, or

Figure 14

Fixed Price Power Supply Tariff		
Term	All Usage through December 31, 2014	
Price Element	Summer Months	Non-Summer Months
On-Peak Usage	\$0.10	\$0.07
Off-Peak Usage	\$0.06	\$0.04

may be a marketing technique to secure customers. Figure 14 is an example of a three-year fixed price offering for power supply (with the distribution charges not reflected).

Vendors of environmentally-preferred power (also known as “green” power) may offer specific power supply rates for specific types of resources (wind, solar, biomass). Figure 15 is an example of a 100-percent wind power offering, with both fixed- and variable-price options. The variable price option means the rate can change every month. The fixed price option is guaranteed to remain stable for a period, typically one to three years.

In some restructured regions (e.g., Alberta, Texas), the distribution utility disappears completely from the utility bill and the competitive power supplier provides a single bill that comprises the charges from the distribution utility and the costs of power supply. In the United Kingdom, these competitive suppliers may offer a multitude of pricing options for small and large users, customers with and without electric space conditioning, and urban and rural dwellers, as well as multiyear pricing options. The customer may use a web-based “shopping” site to compare and contrast alternative pricing structures available to them.

Figure 15

Green Power Offering				
Rate Element	Standard Offer Service Tariff Subject to Monthly Fuel Adjustment	100% Wind Subject to Monthly Cost Adjustment	100% Wind Fixed Price to December 31, 2014	Cancellation Fee For Early Termination
On-Peak Energy	\$0.10	\$0.12	\$0.13	\$10/month of remaining term
Off-Peak Energy	\$0.07	\$0.08	\$0.09	

F. General Service

The term “general service” means any business consumer of electricity. Utilities typically have separate tariffs for small, medium, and large general service classes, generally divided by voltage level, peak demand, connected load, annual consumption, or some other measure of size.

i. Small Commercial

Small commercial consumers include typical office and small retail establishments. Most utilities apply separate demand charges to customers with peak usage over a threshold, such as 20 kW of peak demand. Utility rules specify that customers using more than some monthly amount of electricity – typically about 300 kWh/month multiplied by the demand threshold (i.e., 6,000 kWh/month for the 20-kW example) – will have demand meters installed, and if their usage exceeds a kWh threshold for a number of months per year, they will be subjected to the demand rate.

1. Monthly Fixed Charge

As with residential consumers, a monthly fixed charge is generally applied to recover metering and billing costs. Some utilities include a portion of distribution costs in this charge.

2. Demand and Usage Charges

The major rate components for general service customers are demand charges and kWh usage charges.

The demand charge is typically a rate per kW or kilovolt ampere (kVA) of demand, applied to the highest 15-minute or 1-hour usage during the month. If a customer uses 0 kW at night, 20 kW during most hours of the month, but it rises to 50 kW during one hour of the afternoon of the hottest day, they will be billed for 50 kW of demand for the month, even if the utility’s system peak is at a different hour.

This is one persistent problem with using demand charges to recover a significant portion of costs – there is not a perfect match between an individual customer’s *non-coincident* peak demand and the system coincident peak demand, which actually dictates the utility’s capacity needs. For example, a commercial bakery might have an individual peak demand in the early morning hours, but will pay the same

demand charge as a retail store with air conditioning that has its individual peak demand during the hot afternoon.

Usage charges for this type of customer are generally flat, but sometimes what is called a *transitional* rate design is used to bridge between small customers (who pay for energy only) and larger customers (who pay both demand charges and energy charges). Recall the initial examples we gave at the beginning of this section for small and large commercial customers:

Figure 16

Simple Small Commercial Tariff	
Rate Element	Price
Customer Charge \$/month	\$10.00
Energy Charge \$/kWh	\$0.11

Figure 17

Basic Tariff For Large Commercial Customer	
Rate Element	Price
Customer Charge \$/month	\$20.00
Demand Charge \$/kW/month	\$10.00
Energy Charge \$/kWh	\$0.08

A transitional rate design allows low-volume general service customers to pay an energy-only rate unless their usage exceeds a defined threshold; if that threshold is passed, a demand charge is applied and the energy charge is made commensurately smaller. This type of rate design can eliminate the need to move consumers from one rate schedule to another, but may be confusing to

Figure 18

Residential Fixed Period TOU Rate		
Rate Element	Summer	Non-Summer
Customer Charge \$/month	\$10.00	\$10.00
First 30 kW Demand	No Charge	No Charge
Over 30 kW Demand \$/kW	\$10.00	\$10.00
First 10,000 kWh	\$0.12	\$0.10
Over 10,000 kWh	\$0.10	\$0.06

the consumer. A transitional rate design is generally less desirable than having two separate rate schedules, one for larger customers with demand meters, and one without for smaller customers.

Note that the average rate for the first block is \$0.11/kWh, the same as that of the illustrative rate for the small commercial user, and the average rate for the second block is \$0.08/kWh, the same as the example large commercial rate. The declining block at 10,000 kWh is offset by the demand charge, which applies to usage over 30 kW – a level of demand typically consistent with usage over 10,000 kWh.

3. Innovative Concepts in General Service Pricing

A number of innovative concepts have emerged for pricing for general service customers. These generally attempt to recognize the cost characteristics of the underlying utility system and may vary widely from place to place.

a. Time of Use

Fixed period TOU pricing for general service customers is very common, particularly for larger customers, and has been implemented with relatively simple meters that display usage for two or three time periods. This can be important, because professional office buildings tend to be open for 50 to 60 hours per week, concentrated during the Monday through Friday peak times, whereas retail stores may be open 80 or even 168 hours per week, with half or more of their usage during night and weekend off-peak periods. A TOU rate fairly apportions costs between different customer types. Fixed period TOU rates define both the time period and the price in advance, so that customers can plan accordingly.

b. Dynamic Pricing

More advanced rate designs are becoming more commonplace for commercial customers. These include various forms of dynamic pricing, as discussed previously under Residential Rates. They are discussed in the companion publication to this paper, Time-Varying and Dynamic Rate Design.

c. Rolling Baseline Rates

Rolling baseline rates have been used in a few jurisdictions to apportion a limited low-cost resource

among customers. Each customer receives an allocation or “baseline” of low-cost power (often from a limited resource, like hydro) at a lower price. The concept originated from economic development rates (see below, under Special Contracts) where industrial customers received lower prices for increased usage. The allocation is based on a percentage of the customer’s usage in a previous year (or years). Usage in excess of this amount is billed at a higher price, reflecting new resources or LRMCs. In at least one case (BC Hydro, in British Columbia, Canada), savings below the allowed baseline are credited at the higher price, to provide encouragement to reduce usage.

A rolling baseline rate for a general service customer may have the following form:

Figure 19

Rolling Baseline Rate	
Rate Element	Price
Customer Charge	\$10
Demand Charge	\$10.00/kW
Baseline Usage Up to 85% of 3-Year Average	\$0.08
Usage in Excess of Baseline	\$0.12

The effectiveness of a rolling baseline rate is probably very limited. While the theory is that these customers will see the higher marginal rate when deciding to build new facilities or expand existing facilities, and therefore invest more diligently in energy efficiency measures, a sophisticated customer will see through the rate design, and understand that the higher block rate will only be relevant for a few years.

G. Large User Pricing

The term “large user” has different meanings in different countries. For the purpose of this discussion, we will use a break point of 250 kW of demand, a usage level at which monthly energy bills are typically \$10,000 per month or more. Large supermarkets, shopping centers, office towers, and most larger manufacturing facilities fall into this category. Larger customers are more likely to have at least one person who (perhaps among other management responsibilities) is in charge of energy purchasing and

energy management. Some utilities call these customers “key accounts” because a small number of them amount to a high percentage of total energy sales.

Rate structures for large users are typically more complex than for small users.

i. Monthly Fixed Charge

The monthly fixed charge for a large user is typically higher than for other customers, because they require more expensive metering and customer-specific services, such as customer communications and quality assurance, customer relations, and specific load management and revenue forecasting tasks.

ii. Facilities, Demand, and Usage Charges

Customers in this category always have dedicated, customer-specific facilities, such as transformers that are not shared with other customers. Often tariffs include fixed facilities charges to recover the costs of this equipment. This class of customers is often charged for power factor, a measure of the current drawn by the customer compared to the kW demand measured by the customer’s meter. This is a complex engineering calculation, but typically does not add very much to the bill unless the customer has a very different pattern of current draw vs. power consumption.³⁷

Usage charges for energy are often seasonally differentiated, and very often applied in TOU periods. A typical tariff for a large user group might have the following form:

Figure 20

Rate for Large User (over 250 kVA demand)		
Rate Element	Summer	Non-Summer
Customer Charge	\$100.00	\$100.00
Demand Charge (\$/kVA)	\$10.00	\$5.00
On-Peak Energy (\$/kWh)	\$0.12	\$0.08
Mid-Peak Energy (\$/kWh)	\$0.09	\$0.06
Off-Peak Energy (\$/kWh)	\$0.06	\$0.04

III. TIME-OF-USE VS. REAL-TIME PRICING

The term TOU generally refers to a rate design in which the periods and prices are fixed in advance. Real-time pricing (RTP) generally refers to a rate design in which the prices charged change in response to real-time changes

in the cost of production for the utility or the wholesale electricity market prices. RTP is a form of dynamic pricing, and it is discussed in the companion document.

iv. Innovative Concepts: Rolling Baseline Rates

As with commercial rates, rolling baseline rates can be established for large users. This can ensure, for example, that a large new heavy industrial load does not cause severe rate impacts for existing customers. Several countries have imposed higher prices on new large industrial customers than those paid by existing customers. This might be accomplished by putting all customers in the class on the same tariff, but then giving existing customers (as of a specified date) discounted rates under special contracts to existing large industrial customers; another approach is to eliminate existing rate classes (i.e., closing them to new customers while leaving existing customers in them), and creating new, higher-priced rate classes for all new customers.

v. Dynamic Pricing

In recent years, many forms of advanced pricing for large users have become commonplace. These include variations of RTP, plus another concept, known as critical peak pricing, or CPP. These are discussed in the companion publication, Time-Varying and Dynamic Pricing.

H. Special Contracts

Utilities often enter into special contracts with very large users. This is most important where a utility serves a very large industry, for instance, an oil refinery, smelter, or auto assembly plant, because that one customer may represent a large percentage of the utility’s sales. Special contracts can protect both the customer and the utility.

Special contracts have also been used for economic development (lower prices for increased usage) or economic retention (lower prices to prevent closure of an existing

37 The power factor is defined as the ratio of the real, or active power (measured in watts) flowing to the load to the apparent power in the circuit (measured in volt-amperes), and is a dimensionless number between 0 and 1. Real power is the capacity of the circuit to perform work.

facility). When this is done, the foregone revenue (the lost increment that would have been collected under the “normal” industrial tariff) may be borne by other consumers, by the utility shareholders, or divided between them.

A special contract is appropriate where a utility incurs significant costs to secure the ability to serve a customer, and the customer does not pay for these in an upfront charge. This is often the case for special transmission and distribution facilities that are needed to provide service to an industrial customer. Special contracts may also be used to set forth specific interruptibility rights for the utility in exchange for a discounted price, or to manage the periodic large spikes in usage when specialized equipment is started.

In addition, if the large customer desires a predictable price for power, either the utility or the customer must enter into a contract with a power supplier for a long-term supply at a contract price. If it is the utility taking that risk, it may want an agreement with the ultimate customer that sets out the financial obligations of the parties (liquidated damages), in the event that the contract is abrogated.

One common approach for serving very large customers is for the customer to pay the costs of extending transmission and distribution lines from the utility to the customer (either in a connection charge or a long-term contract price). For smaller customers, only the cost of distribution facilities is a special per-customer cost and upstream costs are recovered in general rates; but for large industrial customers, augmentation of transmission and substation facilities can amount to millions of dollars of utility investment, and the utility may want some sort of contract to assure these costs are paid by the industry, even if its facilities do not operate.

Power supply is generally handled separately from the incremental wires costs. In some cases, the utility supplies the customer under a defined contract, often tied to specific resources acquired to serve them. In other cases the utility serves the customer, but at “market-based” prices, and does not enter into a long-term contract. In restructured utility systems, the industrial customer contracts directly with wholesale suppliers, and the utility bears no risk, and so there is no need for a special contract for power.

6. Treatment of Carbon Dioxide and Other Emissions Costs

Fossil-fueled power plants produce air emissions, and these emissions can have a cost that must be reflected somewhere in the utility rate design.³⁸

Power plant owners install pollution control devices to control oxides of nitrogen, sulfur dioxide, ozone, mercury, and other pollutants. The installation and operation of these devices is a significant cost. The cost of these devices is generally associated with the energy or kWh component of rates for the following reasons.

First and foremost, the costs of pollution controls, particularly at coal-fired power plants, are generally related to the combustion of fuel for energy. Although emissions control facilities are sized to a particular power plant, the underlying benefit of a coal plant over a natural gas unit is to reduce fuel costs, which are per-kWh costs. Both the plant investment and operating costs of pollution controls are therefore appropriately placed with the kWh charge.³⁹

Furthermore, the installation of pollution control equipment generally reduces the generating capacity or output of the plant during all periods, because the equipment requires power to operate, reducing the amount that is delivered to the grid.⁴⁰

Carbon dioxide emissions are increasingly coming under regulation around the world, including in New England and California. These emissions are a function of the output of the power plants – the more fuel burned, the more carbon is emitted. The costs of carbon dioxide emission allowances (or control costs) therefore should be reflected in the per-kWh usage rates for electricity, not in any demand or fixed charges.

TOU rate designs recognize that producing power

during off-peak hours is typically less costly than it is during on-peak hours; however, the same conclusion may not hold if environmental costs are fully accounted (especially instances where coal is a base load and intermediate resource). For many utilities in the United States, Europe, South Africa, and India, incremental usage during peak periods puts additional demand on natural gas-fired or petroleum-fueled power plants, while incremental usage during off-peak periods can be met by operating coal-fired plants. Where this is the case, the incremental carbon emissions are higher during the off-peak period when coal is the incremental power source. It is possible that (if carbon costs were monetized) this differential may completely offset the fuel-cost savings associated with operating a coal plant, meaning that there should not be an off-peak overall rate discount.

38 For a more detailed discussion of pollution control costs and cost recovery, see Farnsworth and Lazar, 2011.

39 The appropriateness of including such costs in usage rates is further clarified when one considers the difference between base load and peaking generation. A utility would not build a base load coal plant just to serve peak demands that occur for a few hours per year – a peaking plant or a demand-response program would meet those needs at much lower cost.

40 Often utilities will also do capacity upgrades to power plants when they are shut down for retrofit of pollution control equipment, but these upgrades are separate from the pollution control investment, and add costs over and above the cost of the pollution control equipment.

7. Tariff vs. Market-Based Pricing

Traditionally, utilities had prices that remained fixed until the regulator or oversight board or agency approved changes in them. In regions with a restructured utility system, this has changed, and many utility consumers have access to market-based pricing for at least a portion of service. Even where the regulator sets the prices, however, utilities often have one or more adjustment mechanisms that operate between rate proceedings.

A. Traditional Tariff Pricing: Rates Defined Until They are Changed

In traditional utility regulation, prices are set *ex ante* through administrative determination: the regulator approves specific prices, based on the actual historic or adjusted historic costs of specific power plants and wholesale market prices; these prices remain the same until changed by the regulator. This is still the case in many countries, particularly for residential and small commercial consumers. This is known as cost-of-service or “tariff” pricing, because the utility charges no more or less than the tariff that has been approved and is in effect for electricity service.

B. Market Prices

In regions where restructuring has separated the distribution utility from the power supplier, consumers may have a choice of power suppliers. These suppliers may offer a choice of prices fixed for a term (typically 12-36 months), or a variable price that changes more often (seasonally, monthly, or even daily). Or they may offer a package bundled together that includes power supply, delivery, and even other unrelated services, such as cable television or natural gas service.

C. Long-Term Contract Prices

Long-term contract prices for power supply are usually available only to wholesale or very large purchasers – utilities, power marketers, large industrial customers, and

aggregators of small customers. The owner of a specific power plant or fleet of power plants may offer a long-term price that ensures their profitability, but only to customers large enough to make it worthwhile to participate in the wholesale-level market.

D. Adjustment Clauses

Many utilities have costs that fluctuate, which they argue is due to circumstances beyond their control, and many regulators have approved adjustment clauses to track and recover these costs, through adjustable surcharges, between rate cases. The theory is that, due to the volatility, it is difficult to calculate a rate that includes these costs because they are not known or static for any given period of time. The adjustments may be “automatic,” meaning that they operate without any immediate action by the regulator, or they may require an estimate based on a calculation that is submitted to the regulator for approval before they take effect. In either case, there is usually a review of these costs annually or semi-annually that may include an audit, with a true-up to resolve any difference between the estimated cost and the actual.

Consumer advocates generally oppose adjustment clauses, because they can become perennial “single issue” rate increases, without considering offsetting factors that would lead to lower rates if considered at the same time. They also result in rate increases without any examination of the cost allocation or rate design issues that might mitigate the impact on some consumers.

Other adjustment clauses have been used to track and recover conservation program expenses, taxes, pollution control expenditures, nuclear decommissioning, and a variety of other costs. When itemized on a utility bill, these adders tend to confuse consumers. The long list of adjustments that appear on some bills disguises their actual effect on the price per kWh. More important, they often prevent the consumer from seeing how much they would save (incur) if they used less (more) power. After discussion of these adjustments, we provide a comparison between a

utility bill with all of the adjustments separated out, and one with them all shown embedded within the rate – the actual change that consumers would see on their bill. The difference can be very substantial.

One advantage of a restructured utility framework, with separate competitive power suppliers, is that retail consumers may be able to choose a supplier that absorbs, manages, or even avoids the risks of fuel, environmental costs, and other elements that often are included in adjustment clauses for vertically integrated utilities.

i. Fuel and Purchased Power

The most common type of adjustment mechanism is the fuel and purchased power adjustment clause. This calculates the utility's actual costs for fuel and for power purchased from other producers each month, and adjusts the retail price for changes in wholesale costs. These emerged in 1973-74, when oil prices soared, and have remained in place for many utilities since that time. Most of these mechanisms recover costs in the form of a uniform surcharge per kWh; some adjust that surcharge for voltage level; a few recover the surcharge as a percentage of power supply cost, effectively giving a smaller surcharge (or credit) to large-volume consumers.

ii. Environmental Cost Recovery

As emission controls became a significant cost for utilities, some regulators treated them like ordinary utility costs and waited for utilities to file general rate proceedings to recover them, perhaps offset by other cost reductions. Many regulators established tracking mechanisms for the associated costs. In these tracking mechanisms, sometimes the investment and operating costs are passed through the adjustment mechanism, and in other cases, the investment in scrubbers and other equipment is addressed in a general rate case as an addition to rate base, with only operating costs passed through the tracking mechanism. Where cap-and-trade mechanisms have been used for emissions (e.g., sulfur dioxide in the United States), the costs and revenues associated with trading allowances may flow through a tracking mechanism.

iii. Energy Efficiency Programs

Numerous utilities have implemented energy efficiency programs. One means of cost recovery is an energy efficiency tracking mechanism, or “public benefits charge.” A common form for these mechanisms is a uniform

surcharge per kWh, with the funds sequestered into an energy efficiency fund. The level is based on the energy efficiency budget, but actual expenditures may be slightly higher or lower than the budget. Utility expenditures for efficiency then draw from this fund. The fund balance, positive or negative, accrues interest. The actual surcharge on customer bills is adjusted periodically to keep the fund solvent. A few regulators have allowed energy efficiency cost recovery on a uniform (\$/month) surcharge on each customer, rather than a surcharge per kWh. Some critics have argued that energy efficiency costs should not be separated out from other power supply costs, and that these energy efficiency charges should therefore be included in the power supply adjustment mechanism or in base rates.

iv. Decoupling and Revenue Stabilization

An increasing number of regulators have implemented revenue decoupling or revenue stabilization mechanisms. By breaking the link between sales and revenues, these mechanisms remove the incentive for utilities to sell additional power, which assists energy efficiency efforts, and, depending on the breadth of the mechanism, may also protect utility net income from variations due to weather, economic conditions, conservation efforts, or other factors.

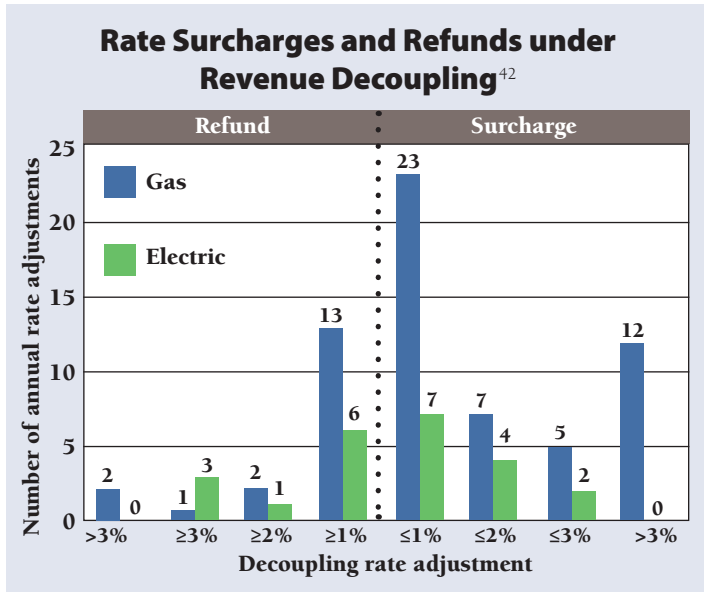
Decoupling ensures that the utility collects its allowed revenue, as determined by the regulator in a rate proceeding. It accomplishes this by empowering the utility to make small adjustments to rates over time so that the allowed amount of revenue – no more, no less – is received. Under traditional rate making, the rates are fixed, and actual revenues are a function of actual sales. Insofar as sales differ from the expected sales levels assumed in the rate case, actual revenues will differ from the allowed revenue of the rate case. In contrast, under decoupling, the actual revenue will equal the allowed revenue, and it is price that varies.⁴¹ Most decoupling mechanisms meet the rate making goal of rate stability by allowing a maximum change of no more than, say, three percent in rates in any year. They have the effect of reducing or eliminating a number of significant risks to stable earnings, such as

⁴¹ Actual and allowed revenues may not necessarily be the same. Many decoupling mechanisms will make other, non-sales-related adjustments to revenue, for example, to deal with the effects of changing numbers of customers, inflation, and increases in productivity.

weather and economic variability, for both the utility and the consumer.

In states where decoupling mechanisms have been implemented, the typical annual rate changes due to the mechanism have been smaller than 3 percent. By contrast, the fuel and purchased power adjustment mechanisms that many electric utilities use cause price changes of 5 and 10 percent on a regular basis – and natural gas purchased gas mechanisms have caused annual rate changes of 20 percent or more.

Figure 21



For a full discussion of this subject, see RAP’s 2011 publication, Revenue Regulation and Decoupling.⁴³

v. Smart Grid

A number of utilities have embarked on grid modernization programs, including investment in AMI, which provides very detailed information on customer usage. These smart grid investments often produce no additional revenue in the short run, and some regulators have allowed surcharges to recover these costs. Some of the surcharges have been on a per-customer basis and others on a per-kWh basis.

Because these adders recover distribution system costs, they apply equally to restructured systems where regulators allow them. Critics argue that smart grid assets should produce immediate cost savings, for example, elimination of meter reading costs, and therefore should be considered in general rate cases where rising capital costs can be offset

with declining operating costs.

The touted benefits of smart grid assets includes not only automated meter reading and enabling dynamic pricing, but also reduced line losses, faster outage restoration, load balancing, and other elements. The only point of this discussion of rate-design for smart meter investment cost-recovery is that the pricing design to recover the costs should follow the benefits, and not be attributed entirely to the metering function. A per-customer charge for smart grid and smart meter improvements is not an appropriate method.

vi. Infrastructure

A recent twist on the adjustment mechanism is being called an infrastructure tracker. Many utilities are replacing aging or obsolete distribution system equipment with new, higher-cost equipment. In situations where the new equipment produces no new revenues, utilities have argued that they should not need to wait for a general rate proceeding, because there are no offsetting cost savings. Most regulators have declined these proposals, taking the position that operation and maintenance expenses are reduced when new equipment is installed, so the costs should be considered in a general rate proceeding. Where infrastructure trackers have been approved, a separate line item may be added to the bill. Because these adders typically recover distribution system costs, they apply equally on restructured systems where regulators allow them.

vii. Taxes and Franchise Fees

A discussion of the typical adders and surcharges on utility bills would be incomplete without touching on taxes and franchise fees, even though these are not costs associated with the actual provision of utility service. Various national, state, and local governments add taxes to utility service. These take the form of value-added taxes and sales taxes, gross revenue levies, or fees for the utility’s use of the right-of-way over and under city streets. Franchise fees are paid to cities for the privilege of doing business within their boundaries. Sometimes these taxes and fees are built into the tariff price for electricity, but often they are separately stated on the bill in part so that they can be clearly attributed to the government entity imposing them.

42 Lesh, 2009.

43 Lazar et al., 2011.

xiii. A Sample Utility Bill with Adjustments

The top part of Figure 22 is an example residential electricity bill, with all of the separate rate elements shown, including an inclining block rate, several adjustments, and two separate taxes. On the bottom, the “rolled up” rate that the customer pays is shown, including all of the adjustments within the rate design, showing the effective price paid for each element of usage. It is critical for customer understanding that the “rolled up” rate be computed and displayed on the bill, so that consumers can understand how much they will save (incur) if they decrease (increase) usage.

ix. Voluntary Environmentally-Preferred Power Programs

Many utilities and non-utility power suppliers offer customers the option of buying a “green power” product, as an alternative to the regular utility fuel mix that may

contain nuclear, coal, natural gas, and other resources. Some of these programs allow customers to specify the power source; all-wind and all-solar offerings are quite common. As a general rule, these environmentally-preferred resources are more expensive than the general utility fuel mix, so a higher price is required.

The most common way these programs are structured is with a uniform surcharge per kWh for the green power product, but sometimes customers can choose to “green up” a “block” of 100 kWh for a fixed fee, or choose a mixed portfolio of 50 percent green power. These tariff increments apply over and above the regular price paid by all other customers. In this framework, green power rates are compatible with any rate design – inclining block, rolling baseline, TOU, or even dynamic pricing. Where a tariff increment method⁴⁴ is used, customers choosing green power will still see the fuel adjustment (for fossil-fuel costs) on their bill.

Another approach is to create a completely separate power product, with cost-based pricing for the green power portfolio. This is the common approach among competitive power suppliers operating in restructured regions, but is also used by some vertically integrated utilities. In this approach, because the green power rate is recovering the actual cost of the wind, solar, or other renewable power source, the customer is not subject to a fuel adjustment mechanism.

Figure 22

Comparison of “Itemized” and “Rolled Up” Bill			
Your Usage:		1,266 kWh	
Base Rate	Rate	Usage	Amount
Customer Charge	\$5.00	1	\$5.00
First 500 kWh	\$0.04000	500	\$20.00
Next 500 kWh	\$0.06000	500	\$30.00
Over 1,000 kWh	\$0.08000	266	\$21.28
Fuel Adjustment Charge	\$0.03456	1,266	\$43.75
Infrastructure Tracker	\$0.00789	1,266	\$9.99
Decoupling Adjustment	\$(0.00057)	1,266	\$(0.72)
Conservation Program Charge	\$0.00123	1,266	\$1.56
Nuclear Decommissioning	\$0.00037	1,266	\$0.47
Subtotal:			\$131.33
State Tax	5%		\$6.57
City Tax	6%		\$8.27
Total Due			\$146.17

Effective Rate Including All Adjustments			
Base Rate	Rate	Usage	Amount
Customer Charge	\$5.565	1	\$5.57
First 500 kWh	\$0.09291	500	\$46.46
Next 500 kWh	\$0.11517	500	\$57.59
Over 1000 kWh	\$0.13743	266	\$146.17

44 The “tariff increment method” here refers to the practice described in this paragraph of adding an additional per/kWh charge to each additional unit of electricity purchased to reflect the selected green energy that is preferred by the customer. As presented here, the normal recovery rate of fuel costs still applies, but the green attributes are added as an increment to the unit charge.

8. Pricing for Small Power Producers

An increasing number of consumers are installing photovoltaic arrays on their homes and businesses. Most of these systems are sized so that they meet much, although not all, of the customer's on-site power demand, but the power production and power consumption take place at different times. Therefore, sometimes the customer is feeding the grid, and sometimes the grid is supplying the customer. Regulators establish prices that the utility pays (or credits) the customer when the customer is feeding the grid. These take several forms: wholesale power credits, net-metering, and feed-in-tariffs (FITs), which are three common frameworks for compensation.

A. Wholesale Power Payment

Some utilities take the position that power generated by small power plants has the same value as wholesale electricity available to the utility in the power market, their so-called "avoided cost" for generation. They are willing to accept power, but only if it is fed to the grid through an approved interconnection rate, and the customer takes its power supply from the grid over a separate interconnection rate, at a regular tariff (or market) rate, typically in the \$0.10 to \$0.15 per kWh range. The utility then pays for all power generated at a wholesale market rate, typically \$0.04 to \$0.08 per kWh on main-grid power systems with diverse generating resources. Sometimes these prices are adjusted by season and by time of day. This approach is generally the least favorable to the customers owning these systems.

B. Net Metering

Net metering is an approach in which a customer with a generating resource takes power from the grid when his on-site generator is not producing all he needs, and feeds power to the grid only when it is in excess of his on-site power needs. The customer pays the utility only for the "net" amount of power flowing through the meter. For example, if the customer's PV system produces 600 kWh

per month, and the customer uses a total of 1,000 kWh per month, the customer pays only for the "net" of 400 kWh usage. This gives the customer the equivalent of the retail rate for their electricity – a rate that includes various surcharges, typically includes a significant component for distribution cost, and may include various adders and taxes. A net-metering mechanism may include a TOU rate, in which the customer is paid at the on-peak rate for power received at that time; this approach is generally favorable to owners of solar PV systems where the peak TOU rate periods coincide with highest load day-time demands.⁴⁵ The net-metering mechanism may also give customers credit at the end-block rate for the power their system produces, because the "net" power through the meter is reduced by the output of the on-site generating unit.

Net metering is generally much more favorable to owners of on-site generation than is a wholesale power supply credit.

C. Feed-in-Tariffs

The term FIT generally means a price paid for renewable energy generation that is intentionally set at a premium to encourage installation of renewable generating facilities, often smaller-scale facilities distributed throughout the system. FITs that were developed in Germany in 2000 were established at very favorable rates up to €0.57 (\$0.80) per kWh. This stimulated very rapid expansion of solar energy in Germany – a country with relatively poor insolation levels compared with desert regions of Africa, North America, Australia, and Asia. Although the very high FITs adopted in Germany and Spain have since been dramatically scaled back, FITs have been adopted by about

⁴⁵ High penetrations of PV systems on the customer-side of the meter can lead to situations in which peak day-time demands also coincide with high levels of supply from variable energy sources resulting in lower "net" loads for system operators. This has occurred recently in certain markets in Europe.

50 countries – from Algeria to Ukraine.

Technically, a wholesale power payment meets the definition of an FIT: *a price paid for all output of an energy system*. The difference is that the term FIT has clearly come to imply a *premium* price designed to encourage development, whereas a wholesale rate credit treats renewable energy just as it would a natural gas or coal-fired generator.

FITs tend to be favorable to renewable energy resource owners, but this is driven entirely by the level at which compensation is set in the tariff. Most FITs, by design, gradually ramp down the price paid for renewable power, providing a stronger incentive for early installations, on the theory that the cost of installing new renewable energy systems will decline as they become more commonplace. For a complete discussion of FITs, see NREL, 2009.⁴⁶

D. Bidirectional Distribution Pricing

When customers install on-site generation but remain connected to the grid, they sometimes take power from the grid, and sometimes deliver power to the grid. The issue of whether and how these customers should share in the cost of the grid has become a more important topic as the prevalence of on-site generation increases.

Advocates of distributed energy argue that this benefits the grid, because most on-site generation will be used a very short distance from where it is generated, reducing grid congestion and losses, and improving grid reliability,

and so should not have to contribute additionally to distribution system costs. This perspective suggests that a net-metering rate may be fair as a long-term rate design.

Some utilities, on the other hand, have argued that these customers require large transformers and interconnections, even though the net flow through the meter may be very small, and so should share significantly in distribution system costs. They have proposed fixed charges for connection of customer generation to the distribution systems.⁴⁷

One approach to address a long-term, cost-based distribution pricing scheme for customers with renewable energy systems would be a bidirectional distribution rate. This approach would charge a small distribution charge for all power taken from, or delivered to, the grid. It could have the form seen in Figure 23.

This approach would collect the same distribution revenue from a customer without self-generation that received 1,000 kWh/month from the grid as it would from a renewable-energy customer that received 600 kWh/month from the grid (when their renewable system was producing less than their need) and delivered 400 kWh to the grid (when their renewable system was producing more than their need). This approach should address utility concerns about revenue recovery, without resorting to high fixed-charge tariff designs that penalize multifamily and other small residential users.

There are endless variations on the theme of this rate design; the basic principle is that all users of the distribution system should share in the costs of building and maintaining that system.

SFV pricing, discussed in section 10 allows all distribution costs to be collected in a monthly fixed fee. Advocates of SFV argue that SFV suffices as a pricing mechanism for customer-sited power production,

Figure 23

Bidirectional Renewable Power Tariff		
Rate Element	What it Covers	Example Rate
Customer Charge	Bimonthly metering and billing	\$5.00
Facilities Charge	Customer-specific distribution facilities	\$1/kw/month
Shared Distribution Facilities & Service	All other distribution costs	\$0.03/kWh coming or going
Power Supply \$/kWh	Generation/Transmission	\$0.08 off-peak; \$0.12 mid-peak; \$0.20 on-peak; \$0.50 critical
Decoupling Adjustment	Revenue Stabilization	Coming or going +/- ~ \$0.003/kWh

46 Cory et al., 2009.

47 San Diego Gas and Electric, 2012.

because the renewable system needs a connection adequate to serve its net need (when its system is producing) or its total need (when it is not), and that capacity stands idle when not being used. Advocates of usage-based rate design respond that there is a high likelihood that the capacity (other than customer-specific facilities, sometimes including line transformers) unused by this customer at certain times would be used by other nearby customers, and therefore a \$/kW/month charge would be unfair. Advocates of renewable energy systems argue that the renewable system most likely serves a load very nearby, on the same distribution circuit, and therefore actually reduces the cost of distribution system capacity for other customers. At much higher levels of distributed renewable energy, however, the reverse can hold, unless time-varying rates are also used to encourage management of these loads through domestic storage (e.g., thermal hot water).

Arbitrating this (or other) debates over rate principles is the role of the regulator. Because the issue of customer-sited generation is relatively new, there are not well-defined regulatory principles and precedents to cite. A case can be made that all costs should be recovered in usage charges, akin to pricing in competitive sectors. Given longstanding utility and regulatory practice and the challenge of fairly

allocating costs across customer classes, a reasonable approach is to limit the monthly grid access charge to the costs of metering and billing; the costs of all other distribution facilities (substations, distribution circuits, and line transformers), which are shared, should be recovered in usage-related charges.

Tariffs and tax policies might inadvertently support investments in distributed generation. For example, if an individual is able to obtain state or federal tax incentives for installing a private photovoltaic system, and by doing so, avoid administrative costs, distribution costs, utility revenue taxes and power supply costs, a profitable business case for distributed generation might be created – even if a societal benefit-cost analysis would show the investment actually costs more than it is worth. Careful attention to legislative and regulatory policies is required if the objective is to stimulate cost-effective investment but not uneconomic investment. As some distribution utilities raise the fixed charges for grid connection, they create incentives for customers to install batteries on local systems and take other steps to sever their connections to the grid entirely, leaving stranded grid costs to be re-allocated to remaining grid customers. This can lead to a death spiral for distribution utilities.

9. Transmission and Distribution System Expansion Planning and Charges

A portion of the utility tariff applies to services other than usage of energy. This includes the fees for expanding a system to serve new areas, connecting a new customer to an existing system, and fees for disconnection, reconnection, special billing periods associated with move-in and move-out, and others. We discuss these only in general terms, as they are generally beyond the scope of this paper.

A. Connection and Service Extension

Expanding utility systems to serve new territory and connecting new customers are sources of both significant cost and significant opportunity for utilities and their regulators. When new buildings, subdivisions, and even new cities are built, there is an opportunity to trade off energy efficiency against the cost of increased production, transmission, and distribution system costs.

i. New Service Territory Expansion

Utilities extend service to new areas not currently developed. The most common example is agricultural land being converted to residential, commercial, and industrial uses on a “plot-by-plot” basis, but in China for example, completely new cities of a million or more residents are being developed as single projects.

When utilities expand their systems, there are costs for transmission and distribution facilities installed in the new area, plus costs for generation, which may be developed on-site (e.g., solar photovoltaics integrated into buildings), may be developed locally (combined heat and power systems and district heating and cooling), or may be developed

remotely (central station fossil, nuclear, or renewable generation).

The key is to have all of these alternatives compared before a decision among them is made. Ideally, energy codes for new buildings and developments will include all energy efficiency and renewable energy measures that are cost-effective compared with the alternative supply-side options available. That is unlikely to be the case without advocacy from the efficiency and renewable communities. Pursuing local, regional, or national requirements for such comparisons may be productive; proposing that it be done at the utility regulatory level may be politically challenging.

ii. New Customer Connections

Nearly all utilities have “line extension” policies that determine how much the utility will contribute to the cost of extending service to new customers. Because a portion of distribution costs is normally recovered in the price for electricity, builders and developers think it is fair for the utility to contribute a portion of the cost of line extensions. Often the developer is required to provide the trench for underground distribution lines, which is easy when they are already trenching for water, sewer, and other underground utilities.

The typical line extension policy is a free allowance of a

Figure 24

Customer Class	Line Extension Policy		
	Provided by Utility	Required of Builder/ Developer	Line Extension Allowance
Residential	Meter	Trench, Meter Base	\$1,000 per customer
Commercial/Industrial Secondary Voltage	Meter	Mast or Trench, Meter Base	3 X estimated annual distribution revenue
Commercial/Industrial Primary Voltage	Meter	Mast, Panel, Meter Base, Communication Line	3 X estimated annual distribution revenue

fixed amount of utility investment per customer, a defined length of system extension, or some multiple of expected annual revenue calculated to reflect the margin, above extension and connection costs, that the utility will receive.

When newly constructed buildings are first connected to a utility system, there is an opportunity to assure high levels of energy efficiency. This can be done through hookup standards, hookup charges based on load (sometimes called impact fees), or through incentive mechanisms, such as credits against hookup fees for exceeding minimum standards, building codes, or new construction energy efficiency programs.⁴⁸

Examples of this are a minimum efficiency standard that must be met in order to connect to the system and a fee for connection to the system for structures not meeting this threshold. Although establishing building efficiency standards is not common for electric utilities, adopting engineering standards that govern the use of electricity (such as minimum power factor requirements) is quite common. Taking the next step – minimum standards for buildings and appliances – is a potentially valuable and important element of a clean energy future.

iii. Increased Customer Capacity

Often existing customers request changes to their service to enable them to use additional power. This creates an opportunity for the utility to review the energy efficiency of both existing and proposed uses, to see if the additional capacity is actually necessary, or if it can be displaced by more efficient energy end uses. Actions taken in this review can be either voluntary (educational only) or mandatory (additional capacity is not permitted without demonstration of efficiency). The degree of regulatory involvement in

the expansion of service to existing customers may be an issue of political sensitivity in many areas; in particular, builders and contractors see this as another obstacle to development.

The fee for expansion of capacity should be imposed at the time of expansion, and, if it is to reflect the incremental cost of distribution system capacity, it should be significant (hundreds of dollars per kW of additional capacity). If large enough, it will stimulate the customer to consider energy efficiency and other alternatives and to invest in those that are the lowest-cost means of providing service. Even so, there is a valuable role that utility analysts can play in helping the customer access and understand the technologies and long-term cost/benefit of energy efficiency measures at this decision point. Because existing customers normally receive their power on a tariff that includes lower-cost resources (often vintage resources), they benefit from investments made by earlier customers. Managing expansion in this way serves to benefit all customers served by the tariff.

Some utilities have a monthly fee tied to the electric panel size of residential consumers. Although it is generally

48 Lazar, 1991.

49 Energy Star™ is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy and is an international standard for energy efficient consumer products. For more information see: <http://www.energystar.gov/>

50 Customer requests for increased capacity could, of course, be treated in a manner that is similar to the hookup or “impact” fees for new service, with potential offsets for energy efficiency improvements.

Figure 25

New Customer Connection Standard			
Customer Class	Required	Connection Charge	Credits for Exceeding Minimum Standard
Residential	Meet International Energy Code	\$20/ampere of panel capacity	Up to \$40/ampere of avoided panel capacity for Energy Star™ ⁴⁹ measures
Commercial/Industrial Secondary Voltage	Meet International Energy Code	\$200/kVA of transformer capacity	Up to \$400/kVA for beyond-code measures with engineering analysis
Commercial/Industrial Primary Voltage	Meet International Energy Code	\$200/kVA of connected load	Up to \$400/kVA for beyond code measures with engineering analysis

undesirable to recover distribution costs in a fixed fee (see discussion on SFV rate design in Section 10), this may be a way to provide a lower cost service to small-use residential consumers, in particular, low-income users, while recovering the full cost of serving large-use customers from those specific customers. See the examples below for Eskom (South Africa) and PLN (Indonesia).

iv. Disconnection/Reconnection

Utilities disconnect customers for failure to pay for service in a timely fashion, and also at the customer's request (for example, when a building is expected to be vacant for an extended period). Utilities charge fees to reconnect service after a disconnection. These fees are highly controversial, because many (or most) customers affected are low-income customers. The fees may be a barrier to customers securing restoration of service.

Utilities often seek to make disconnection and reconnection self-funding – that is, to set fees so they cover the cost of a special visit to the premises to disconnect and reconnect power service. With the advent of smart meters, disconnection and reconnection can often be done remotely at very little cost, but this also concerns low-income advocates, because it means disconnection can be effected without direct observation of the situation or an opportunity for field collection (a cash payment when a service person is at the house to disconnect service for non-payment); in some cases, persons who have medical equipment that depends on reliable electric service may be

disconnected. It also means that disconnection may occur sooner than it has for utilities using traditional meters. If disconnection is done remotely, then the disconnection and reconnection fees should be removed, or at a minimum, greatly reduced to reflect the removal of the cost to the utility of sending a person to the customer's premises.

For rental properties, where one tenant moves out on a day other than the normal meter reading cycle, a fee may be imposed for a special reading of the meter. With smart meters, this can be done remotely at very little cost. Most utilities have mechanisms to allow the landlord to maintain electric service between tenants, so that maintenance personnel and rental officers have access to power.

v. Late Payment, Bad Checks, and Other Miscellaneous Charges

Utilities also impose charges for various miscellaneous costs they incur. Late payment charges and interest are common, as are fees for returned checks, a change of account name, field collection, and other unusual billing and collection costs.

Some utilities rent energy consuming equipment, such as water heaters, and have fees for these rentals. Some utilities provide appliance repair, and have fee schedules for these services. These are generally not regulated services, and the prices are not set by the regulator.

Finally, there are often miscellaneous charges for state and local taxes on electricity service, or for other costs as approved by the regulator.

10. Revenue Stability

Because utilities are capital-intensive and raise billions from investors and lenders, they are very concerned that their net income be both stable and sufficient to service bonds and pay shareholder dividends. There are many ways to provide this stability. In addition, utilities that provide power supply service, in particular, make large commitments in the expectation of providing future service. The amount of service that customers actually use can change significantly over time.

Rate design that encourages efficiency focuses cost recovery on the variable usage-related components of rates. Where consumers vigorously pursue energy efficiency, utility sales decline, and their recovery of costs may be impaired. Regulators have devised methods to protect utilities from the risk associated with long-term investments in these types of situations.

A. Straight Fixed/Variable Pricing

Many utilities have sought, and a few regulators have granted, SFV pricing structures. These collect all of the distribution costs in a fixed monthly fee, and collect only variable power supply costs in the per-kWh rate. This type of rate provides nearly complete stability of distribution revenue to utilities – but this comes at a high price to consumers and the environment, because the per-kWh rates are significantly lower. In Appendix A we compare SFV to more conventional inclining block and flat rates, and show how much additional energy consumption would be expected under SFV.

B. Lost Revenue Adjustment Mechanisms

Several regulators have adopted mechanisms to restore the distribution revenue lost when customers participate in utility energy efficiency programs. These are generally known as lost revenue adjustment mechanisms, or

LRAMs. These mechanisms typically rely on monitoring and evaluation results from energy efficiency programs, including engineering estimates of the reduced sales due to those programs, and allow utilities to use a surcharge to recover the lost revenues, either retrospectively or contemporaneously with true-ups.

The principal shortcoming of LRAMs is they do nothing to eliminate the utility's reliance on sales to meet its revenue needs – that is, the “throughput” incentive persists. A second drawback of LRAMs is their dependence on estimated impacts of energy efficiency programs.⁵¹ An LRAM can encourage a utility to present optimistic estimates of savings or even to pursue biased and inaccurate evaluation processes. In addition, utilities gain an incentive to have all customer energy efficiency efforts focused through utility programs. In one case, a utility actually worked to block adoption of a new building code, because it was receiving an LRAM surcharge when customers participated in a utility-funded voluntary program to build energy efficient buildings; the effect was a lower percentage of new buildings built to high efficiency standards, because not every consumer participated.

C. Revenue Regulation and Decoupling

Revenue decoupling was briefly mentioned as one of many adjustment mechanisms that regulators have approved that often show up as discrete adjustments on customer bills. Revenue decoupling is a mechanism to ensure that a utility receives its allowed revenue requirement, regardless of its sales volumes. Decoupling is not really a pricing mechanism – it can work with any type of rate design – but because it stabilizes the utility revenue, it makes it possible to implement progressive rate designs without impairing utility financial stability.

⁵¹ See Hayes et al., 2011.

Traditional utility rate setting starts with a regulatory determination of the utility's required level of revenues. This is followed by an exercise in cost allocation: by function (i.e., first by production, transmission, and distribution, then classified according to whether the costs are energy related, demand related, or customer related), followed by allocation to the various customer classes of service, and lastly into specific rates. If actual usage changes due to weather, economic conditions, energy conservation, or other causes, the actual revenue will deviate from the assumed revenue. If the change in revenue between rate proceedings is not offset by a change in costs during the same period, the utility can suffer from earnings attrition or gain from earnings accretion. If the deviation is great enough, either the utility or the regulator can initiate a new rate proceeding.

Decoupling starts with the same calculation, but the regulator also determines a level of revenue (or a formula for doing so) that applies into the future, typically for a period of two to four years. If the actual revenue for the utility deviates from the allowed revenue, the utility is allowed a minor rate adjustment to collect or refund the difference.^{52, 53}

There are two basic forms of decoupling: revenue per customer (RPC) and attrition. With RPC decoupling, the regulator sets an allowed revenue per customer; it is, in essence, the revenue requirement divided by the number of customers. The RPC may be adjusted periodically if the decoupling mechanism is approved for a multiyear period. As the number of customers changes, the allowed revenue changes.⁵⁴ In attrition decoupling, the regulator establishes

a total allowed revenue in a general rate proceeding, then annually examines how costs (or, in the case of an alternative regulation framework, proxies of cost that form the basis for the year-to-year regulatory adjustments) have changed since that rate proceeding, and allows an appropriate change in revenue. Under either approach, a periodic rate adjustment is made to allow the utility to receive the allowed level of distribution revenue.

About half of the United States and several other countries have experimented with decoupling mechanisms for natural gas and electric utilities. California has over two decades of experience with decoupling. The net result is more stable utility earnings. Critics of decoupling fall into two categories. First, there are consumer advocates who argue that this represents a shift of risk of the financial impact of changed usage levels from shareholders to bill payers. Some regulators have addressed this by adjusting the allowed rate of return or the company's imputed capital structure. Other critics include industrial customers, who actually prefer that the utility's financial health be tied to the economic strength of its customers, to give the utility an incentive to help its customers be competitive in their respective industries.⁵⁵

D. Rate Design Comparisons

Revenue stability mechanisms permit the regulator to more easily apply economic principles to rate design – to better align incremental prices with long-run incremental costs – while protecting the utility's short-run financial stability.

52 By revenue here, we generally mean the amount of gross revenue or turnover for regulated services. As noted below, gross revenues here can be calculated either on a total turnover basis, or calculated on a per-customer basis. Categories of costs that receive distinct cost-recovery treatment between rate proceedings or annual base-rate adjustments would not necessarily be included in the gross-revenue adjustments. Categories of costs that receive distinct rate recovery treatment might include tariff riders, unregulated services, or categories of costs that receive special treatment. Power costs, for example, are potentially volatile and can be outside the utility's ability to manage over the short term. As such, they may receive adjustments within the year to facilitate timely cost-recovery, or return to ratepayers in lower charges, when power costs rise or fall between general rate determinations.

53 See Lazar et al., 2011.

54 Note that each customer does not pay the allowed RPC. Customers pay bills according to the tariffs under which they receive service and their actual usage. The RPC is simply one element in the formula by which the allowed revenues are determined. RPC decoupling is preferred to other forms of decoupling, especially for distribution-only service, because utility costs vary in the short run (the time between rate cases) more closely with changes in numbers of customers than they do with other variables (such as investment in wires and substations).

55 Lazar et al., 2011.

The four rate designs below are all designed to produce the same total revenue from residential consumers for a utility with average per-customer usage of about 800 kWh/month. The fixed/variable rate and the declining block rate (DBR) both provide the utility great financial stability, but yield a price of electricity that is a fraction of the cost of building new power plants, transmission lines, and distribution circuits. The inclining block rate does a good job of aligning incremental costs with incremental rates, but, if short-run variable power costs are only \$0.05/kWh and sales decline, could leave the utility with a significant revenue shortfall and adverse impacts on earnings.

It is easy to see how the SFV or DBR option will reduce customers’ incentives to invest in end-use efficiency and renewable energy, and lead to higher consumption. An energy efficiency measure that would pay for itself in three years at the inclining block end-rate of \$0.14 would take five years at the flat rate of \$0.09, and eight years at the fixed/variable rate of \$0.05.

We have not discussed declining block rates in this report, because they are essentially an anachronism in the industry that continue to exist in some select regions. Most US jurisdictions eliminated them in the 1980s, when they were required to examine this form of rate design as part of the consideration and determination process required by the Public Utilities Regulatory Policies Act (PURPA). Declining block rates convey a false price signal to consumers, namely, that the unit cost to consumers is lower

Figure 26

Comparison of Four Residential Rate Design Alternatives				
	Inclining Block Rate	Flat Rate	Declining Block Rate	Straight Fixed/Variable Rate
Customer Charge \$/month	\$5.00	\$5.00	\$5.00	\$30.00
First 500 kWh/month	\$0.07	\$0.09	\$0.14	\$0.05
Next 500 kWh/month	\$0.10	\$0.09	\$0.10	\$0.05
Over 1,000 kWh/month	\$0.14	\$0.09	\$0.07	\$0.05

with greater consumption and that the cost of replacing retiring facilities and additional electricity facilities is cheaper than the cost of existing facilities.⁵⁶

Revenue stabilization mechanisms like decoupling are designed to remove the resistance of utilities to rate designs that align incremental prices to long-run incremental costs.

In Appendix A, we estimate how much additional energy consumption would be stimulated by the illustrative SFV rate, and how much would be avoided with the inclining block rate. With relatively conservative assumptions, we show that usage could go up (SFV) or down (inclining block) by about 8 percent, depending on the form of rate design selected.

56 As indicated earlier, later blocks typically have lower load factors and therefore higher unit costs than earlier blocks. Also, the costs of new facilities (as reflected in current estimates of levelized costs) remain well above embedded and existing generation (need citation). This is especially true when environmental retrofit control costs are included and externalities are included in the accounting.

11. Examples of Global Best Practices

This section describes actual tariffs adopted in different parts of the world, which in our view represent some of the best pricing practices today. These examples are not meant to be exhaustive, but are intended to illustrate that actual utilities, reporting to actual regulatory bodies, have adopted progressive rate design options.

A. Residential

The residential (or domestic) sector typically accounts for about 90 percent of utility customers, about 60 percent of utility gross revenues (including power costs), and about 50 percent of utility kWh deliveries. Examples of progressive residential rate designs exist in Asia, the Americas, Europe, and Africa.

i. Western US Inclining Residential Block Rates

In 1978, the US Congress passed the PURPA, which required, among other things, all states to “consider and determine” if certain rate-making standards should be implemented.⁵⁷ Each state convened a public hearing process and reached a written decision following those hearings; most of the rate designs that follow had their genesis in PURPA.

As a result of these regulatory reviews, most of the investor-owned utilities in the western United States have inclining block rate designs. As discussed in Section 5, some of these are based on load factor determinations, some on the existence of substantial hydro resources in utility portfolios, and others on marginal cost considerations. Some of these utilities have strongly seasonal usage characteristics, and focus the rate inversion in the summer months, whereas others, particularly those with large space and water heating loads, apply the same rate design all year.

Many of these utilities also have optional TOU rates for residential consumers, and a few have optional dynamic rate designs available to residential consumers. We present

only the basic residential prices, applicable to customers who do not select a more complex rate design here.

We show three examples of large investor-owned utilities below, in place as of January 1, 2010. All are characterized by a monthly customer charge that approximates the cost of metering and billing, and multiple increasing energy blocks. The Avista rate is simplest – a single rate that applies in both seasons. Avista is a winter-peaking utility, however, which means that there is very little usage in the third block in the non-winter months, so nearly all customers get their energy at the lower block prices.

Figure 27

Actual Inclining Block Rates – Western United States

State of Washington	
Avista Utilities Schedule 1	
Customer Charge	\$5.50
First 600 kWh	\$0.0602
Next 700 kWh	\$0.0712
Over 1300 kWh	\$0.0848
State of Arizona	
Arizona Public Service Rate E12	
Customer Charge	\$7.59
Summer	
First 400 kWh	\$0.0857
Next 400 kWh	\$0.1218
Over 800 kWh	\$0.1443
Winter	
All kWh	\$0.0833

57 Public Utility Regulatory Policies Act, 1980.

Figure 27 (continued)

State of New Mexico		
Public Service New Mexico Rate 1A		
	Summer	Winter
Customer Charge	\$3.10	\$3.10
First 200 kWh	\$0.0676	\$0.0676
Next 500 kWh	\$0.0907	\$0.0820
Over 700 kWh	\$0.1119	\$0.0855

California has taken a different approach to rate design for its investor-owned utilities, driven by a combination of marginal cost considerations and political action by the legislature.

Pacific Gas and Electric and San Diego Gas and Electric both serve a variety of climate zones, from urban areas with small dwellings to rural areas with large homes and no access to natural gas. The state therefore has created multiple “climate zones” and “building types” and has computed separate “baselines” for each type of dwelling in each zone. Customers in colder (or hotter) zones have larger baselines; and customers without access to natural gas also have larger baselines than those who do have access to gas.

Thus, while all consumers see the same prices for each block of electricity, the number of kWh in each block varies from customer to customer, and zone to zone. Although complex, this is an attempt at meeting the objective of fairness in rate design, by differentiating consumers according to the underlying drivers of their energy needs. The rates below were current at November 5, 2011:

Figure 28

Actual Rates of California Investor-Owned Utilities				
San Diego Gas and Electric			Pacific Gas and Electric	
Customer Charge	None	None	Customer Charge	None
	Summer	Winter	Baseline Energy	\$0.122
Baseline Energy	\$0.058	\$0.077	100%-130% of Baseline	\$0.139
100%-130% of Baseline	\$0.079	\$0.099	130%-200% of Baseline	\$0.293
130%-200% of Baseline	\$0.212	\$0.215	Over 200% of Baseline	\$0.333
Over 200% of Baseline	\$0.232	\$0.235		

Critics of the California rate design argue that the very high end-block rates amount to subsidies of low-volume users by high-volume users. Defenders point out that the very low costs of limited amounts of hydropower justify the baseline rates, whereas the low load factors associated with space conditioning, together with the high cost of new resources and the environmental impacts of power generation that are not fully reflected in electricity rates, make these end blocks cost-based.

ii. Andhra Pradesh Residential Block Rate

Andhra Pradesh (AP) is a state in central India whose capital city is Hyderabad. The current residential rate in AP reflects two important progressive principles. First, there is no monthly customer charge. Second, rates are in six inclining blocks, providing low-use households (mostly

Figure 29

Andhra Pradesh (India) Residential Tariff		
	\$/kWh	Rupees
Customer Charge	None	None
0-50 kWh	\$0.030	1.45
51-100 kWh	\$0.057	2.80
101-200 kWh	\$0.062	3.05
201-300 kWh	\$0.097	4.75
301-500 kWh	\$0.123	6.00
Over 500 kWh	\$0.128	6.25
Rate available at: http://www.apcentralpower.com/customer/Tariff.jsp Accessed November 6, 2011		

low-income) with essential service at affordable prices, while making incremental usage priced at a level reflecting the cost of new resources to serve growing demands.

iii. ESKOM South Africa Electrification, Prepayment, and Pricing

During apartheid in South Africa, the white population largely had access to a first-world power system, providing service to large homes with a full complement of modern appliances. After the fall of apartheid in the 1990s, the national electricity utility, ESKOM, was more or less politically directed to expand service to the black townships and shanties as quickly as reasonably achievable.

ESKOM developed both a simple engineering solution and a simple pricing solution to make service expansion possible. First, a “readyboard” was created, which combined the meter, load limiter, and power outlets, so that a single wire could be connected to a transformer, and then the readyboard would be installed in the residence, eliminating the need for an electrician to do work inside the domicile. Second, prepayment cards were made available at thousands of retail outlets; because consumers in the unserved areas had previously purchased kerosene (for lighting and cooking) in small quantities, the prepayment cards were made available in small units. Today they are available from multiple vendors and even vending machines.

Today, more than 4 million South African electric consumers are served through prepayment, while millions more have post-payment accounts. The prepayment meters have become more sophisticated, as have the vending solutions. All residential consumers – prepayment and metered – now are served on a single tariff, with no monthly fixed charge, and a four-block inclining rate design.

South Africa is characterized by a limited supply of lower-cost power from older power plants (hydro, nuclear, and coal), with incremental power coming from much more expensive resources. For this reason, in addition to load factor justifications, a vintage concept would be a cost justification for a block rate design.

Qualified low-income households receive “free basic electricity” of 50 kWh per month; additional use is at the tariff rate. For the large homes with a full complement of appliances, much of the use will be in the fourth block. For most low-income consumers, all or nearly all will be in the first two blocks (plus the free basic electricity allocation).

Figure 30

ESKOM Residential Tariff at November 6, 2011

	\$/kWh	ZA cents
Customer Charge	None	None
0-50 kWh	\$0.083	65.72
51-350 kWh	\$0.095	75.42
350-600 kWh	\$0.137	109.50
Over 600 kWh	\$0.151	120.10

Rate available at: <http://www.eskom.co.za/c/53/tariffs-and-charges/> Accessed November 6, 2011

iv. Indonesia Perusahaan Listrik Negara Social Tariff

The national electric utility of Indonesia, Perusahaan Listrik Negara (PLN), is, by number of consumers, the largest single electric utility in the world, serving more than 245 million people,⁵⁸ the vast majority of whom are very low income. PLN has a mixed resource base, including hydro, coal, oil and gas, and geothermal energy.

Service has been expanded to tens of millions of residential consumers via a “social tariff” in which government appropriations are used to pay for the cost of extending the distribution system, and a three-block inclining rate design is used to collect power supply and operating costs.

The PLN residential tariffs⁵⁹ vary by maximum connected demand, measured in volt-amperes (VA), approximately the same as watts. Consumers on the social tariff are fitted with a load limiter that constrains them to a maximum demand of 450 VA or 900 VA, enough for lighting, a refrigerator, and occasional use of other appliances. Customers needing additional capacity are required to pay the full cost of distribution system expansion, and also pay higher prices for electricity.

Figure 31 shows the tariffs used by most residential consumers. Connected demand of 1300 VA and above is no longer considered part of the “social tariff,” but is applicable to larger households with more appliances.

PLN is currently offering customers on the 450-VA

58 World Bank, 2005.

59 PT PLN (Persero), Electricity Tariff for Residential available at <http://www.pln.co.id/eng?p=553>

Figure 31

Maximum Demand VA (~watts)	Blocks	Price \$/kWh	Price Rupiah
450	Monthly Charge	\$1.12	10,000
	First 30 kWh	\$0.014	123
	Next 30 kWh	\$0.030	265
	Over 60 kWh	\$0.040	360
900	Monthly Charge	\$1.68	15,000
	First 20 kWh	\$0.022	200
	Next 40 kWh	\$0.033	295
	Over 60 kWh	\$0.040	360
1,300	All Usage	\$0.068	605
	Minimum Bill	\$3.515	31,460
2,200	All Usage	\$0.073	650
	Minimum Bill	\$6.39	57,200

and 900-VA tariffs the option to increase their maximum demand, if they convert to prepayment.

One unplanned benefit of this rate design has been the emergence of a market for low-wattage appliances, particularly refrigerators. Although the typical small refrigerator in most countries uses 200 kWh/month or more, models sold in Indonesia are better insulated and have smaller compressors, so they draw lower wattages, enabling their owners to remain on the social tariff. Fluorescent lighting has been overwhelmingly dominant in Indonesia since 2003 for the same reason. The load limiter has been transformed into an efficiency enhancer.

v. Southern Electric (UK) 3-Year Contract Price

Southern Electric (SE) is an electricity retailer in the United Kingdom that offers supply in most parts of England and, through an affiliate, in Scotland. The United Kingdom is a fully restructured market, where a distribution utility provides the delivery service, but competitive providers offer a bundled retail service consisting of power supply plus delivery in a single offering to consumers.

SE offers customers a choice of a market-driven “standard offer” price that changes monthly, or an optional two-year or three-year fixed price. It also offers a choice of

prepayment or regular billing (with a discount for direct debit payment). Because the company can hedge purchases in the market, it takes no risk in offering a two- or three-year fixed price, but essentially passes the cost of securing the hedge on to consumers choosing the fixed-price option in the form of a premium. The premium for the three-year fixed price is 9 percent over the standard tariff.

Figure 32

	Expressed in US Dollars	
	Standard Tariff	Price Fix 7 Tariff
Customer Charge (standing charge)	\$8.75	\$9.65
All kWh	\$0.203	\$0.222

vi. Southern California Edison (and Others) Air Conditioning Interruption Rate Discount

Many utilities offer discounts for customers who have interruptible air conditioner loads. These allow the utility to control these loads whenever system stability is threatened, and during periods when market clearing prices are above otherwise applicable retail rates.

Southern California Edison (SCE) has one of the largest programs of this type. Its Summer Discount Plan, with over 300,000 participating consumers, was created over 25 years ago. The program provides up to 700 megawatts of peak load reduction controlled by the utility.⁶¹ The program is implemented by installing radio-controlled switches on air conditioning units. It is not a part of the new SCE “Smart Connect” AMI network; there is discussion of changing this program to a price-based program using the newly installed AMI system.

The program offers customers a variety of air conditioning interruption options, from one with a minimal impact on comfort, to one with maximum potential bill savings. Customers who have flexible schedules – to shop, go to the movies, or stay in their workplaces – tend to choose the options with more interruptions and larger bill credits. Customers can check the status of their interruption on the web

60 See <http://www.pln.co.id/eng?p=553>, accessed November 6, 2011

61 Christensen Braithwait et al., 2011.

and avoid going home if it would be uncomfortable to do so. The annual savings can be up to \$200 for a home willing to accept frequent interruptions, as shown by the matrix below.

Figure 33

Southern California Edison Summer Discount Plan		
<i>Summer Discount Plan: Maximum Savings/Maximum Comfort</i>		
	Maximum Savings <i>Off continuously up to 6 hours</i>	Maximum Comfort <i>Off 15 out of every 30 minutes for up to 6 hours</i>
Unlimited <i>(Any # of interruptions per summer)</i>	\$200	\$50
Limited <i>(Up to 15 interruptions per summer)</i>	\$100	\$25

vii. Hungary Residential Rate Design

Hungary is a middle-income, central European country, with near-universal electric service provided by several distribution utilities. Most of the wholesale power supply for the regulated market is provided by a federal agency.

Distribution and supply prices are set by the federal regulatory body; to date, all of the regulated utilities have similar prices. Although electricity is relatively expensive in Hungary, care has been taken to minimize the monthly customer (standing) charge, and introduce a limited level of rate inversion. The table below shows retail residential prices for four distribution utilities in Hungary as of February, 2012.

Figure 34

Residential Electricity Prices in Hungary				
Hungarian Forint	EDF	ELMU	EMASZ	EON
Customer Charge	195 Ft	195 Ft	195 Ft	195 Ft
First 110 kWh/month	46.40 Ft	46.85 Ft	47.57 Ft	45.51 Ft
Over 110 kWh/month	47.83 Ft	48.62 Ft	49.40 Ft	48.78 Ft
US Dollar Equivalent				
Customer Charge	\$0.87	\$0.87	\$0.87	\$0.87
First 110 kWh/month	\$0.208	\$0.210	\$0.213	\$0.204
Over 110 kWh/month	\$0.215	\$0.218	\$0.222	\$0.219
<i>Information based on personal communication with Hungarian Energy Office, January 5, 2012</i>				

B. Residential Low Income⁶²

Many utilities in many countries have specific discounts or preferred service for qualified low-income customers. Although many of the utilities discussed previously, including PLN (Indonesia), AP (India), and the four Hungarian utilities, have rate designs that favor small-use residential consumers – and low-income consumers tend to be small users – the rates are not differentiated by income.

Low-income assistance programs take many forms. These include discounted rate schedules, bill-payment assistance programs, disconnection programs, discounted service extensions, and dedicated low-income energy efficiency programs. Energy efficiency services are crucial, provide long-term relief, and are highly cost-effective, but the topic is beyond the scope of this paper.

Discounted rate schedules for low-income consumers are fairly common. In many developing countries, steep inclining block rate designs and elimination or waiver of customer charges are a common way to make essential service available at reasonable cost. The example of South Africa, above, includes 50 free kWh per month for qualified low-income households, enough for lighting and refrigeration, the two end uses defined as “essential” by the United Nations Secretary General’s Advisory Group on Energy and Climate Change.⁶³

i. Seattle City Light Low-Income Rate

Seattle City Light is a large urban US municipal electric utility, serving a population of about one million people. It has a long history of investing in energy efficiency and providing low-income assistance. The utility has an explicit, and significant, rate discount for low-income consumers. This is limited to those customers either receiving supplemental security income or those who demonstrate household income that is less than 70 percent of the state median household income for the number of persons in the household.

62 Lazar, 2002.

63 United Nations Industrial Development Organization, 2010.

Figure 35

Seattle City Light Residential and Low-Income Discount			
	Residential	Low-Income	Discount %
Customer Charge	\$3.50	\$1.75	50%
First 300 kWh Summer	\$0.046	\$0.019	58%
Over 300 kWh Summer	\$0.096	\$0.036	63%
First 480 kWh Winter	\$0.046	\$0.019	58%
Over 480 kWh Winter	\$0.096	\$0.036	63%

ii. UK Fuel Poverty Program

The United Kingdom has a comprehensive program, called Fuel Poverty, to both reduce energy usage by low-income households and make needed energy more affordable. It does not include any explicit discounted utility rates.

The energy efficiency component of the Fuel Poverty program has supported energy efficiency improvements in hundreds of thousands of low-income residences. This has included weatherization, energy-efficient appliances, and fuel-switching investments to convert homes from electric heat to natural gas heat.

The electricity markets component of the Fuel Poverty program has noted that low-income households are more likely to use prepayment, and that this service is more expensive than direct debit of utility bills from a bank account. Signing up for direct debit saves the average participant £144 (\$230) per year. It has worked to improve access to direct debit programs for low-income households, but success is limited, because, when the account cannot cover the amount of the debit, the customer is forced back onto prepayment. It also found that just switching low-income consumers to the lowest-cost supplier available to them would lift 200,000 people out of fuel poverty.⁶⁴ In response, some UK providers have eliminated the prepayment surcharge.⁶⁵ The complex competitive market for electricity in the UK provides many choices, and there are on-line “shopping” sites to help consumers find the lowest cost tariff. To date, however, there is no automatic system for moving consumers receiving heating fuel assistance onto the most favorable tariff.

Fuel assistance payments are provided to people over 60 years of age, approximately 12 million people (out of a total population of 62 million), with payments of up to £200 per winter.⁶⁶ Additional assistance (for non-pensioners) is avail-

able: Warm Front is the current energy efficiency (EE) provider and energy assistance program, and it is being phased out over 2012-2013. Under the Green Deal, there is a program called Affordable Warmth that will help low-income customers improve efficiency of their homes. It is not clear that it would include fuel assistance.

iii. Met-Ed (Pennsylvania) Percentage of Income Payment

The state of Pennsylvania has a restructured electric system, with competitive energy suppliers and regulated energy distributors. Pennsylvania utilities have a low-income bill assistance program that limits a household electricity bill payment obligation to a percentage of the household income.

The Customer Assistance Program (CAP) provides for a sliding scale, based on income, with low-income customers expected to pay no more than 6 percent of their income for electricity. A complex formula considers the customer’s household income, energy cost, and access to other financial assistance. After consideration of other sources of funds, the CAP program bears the “unaffordable” portion of the customer’s energy bill.

The benefit of the CAP is that low-income households have affordable monthly energy bills. There is a downside: these consumers do not see the incremental cost of electricity as their incremental energy cost, and do not have the same incentive to control their usage as do customers paying the regular tariff. To preserve incentives for efficiency, low-income programs need to be designed to provide conservation incentives, or at a minimum, make them sensitive to usage levels.

C. Commercial

Most commercial (small general service) electric rates take a relatively simple form. For very small customers, an energy-only rate is charged, sometimes differentiated by

64 The UK Fuel Poverty Strategy 6th Annual Progress Report, 2008.
 65 e.on UK. Fair Price information available at: http://www.eon-uk.com/about/5673_5772.aspx
 66 Government of the United Kingdom. Working, jobs and pension information available at: http://www.direct.gov.uk/en/Pensionsandretirementplanning/Benefits/BenefitsInRetirement/DG_179916

time of day. For larger customers, a separate demand charge is applied, with a correspondingly lower energy charge.

A few innovative programs have evolved, particularly in regions experiencing rapid increases in energy costs or having a limited low-cost resource that is augmented with much higher-cost newer resources.

i. British Columbia Rolling Baseline Rates

British Columbia (BC) is a Canadian province with a very large low-cost hydroelectric base. Policymakers have determined that increased use of electric power should bear the cost of more expensive new (often hydro) resources. They have achieved this for the commercial sector through what is called a rolling baseline rate. Customers receive an initial baseline allocation of power, based on their historical usage, at a low rate, and pay a higher rate for increased usage. If usage falls below the baseline, customers get a credit based on the higher-cost new resources, because they are helping free up low-cost resources for other customers to buy, avoiding the need to build new resources.

The rate design is complex. It applies to large commercial customers, typically the size of a shopping

center or office tower. Usage up to the baseline is charged at a rate of \$0.0444/kWh, and usage in excess of the baseline (or reductions in use below the baseline) are charged (credited) at \$0.0668/kWh, a 50-percent premium on the energy charge. The effect is that these consumers measure the cost effectiveness of energy efficiency or on-site generation measures against the higher (new-resource) rate of \$0.0668, not the lower (vintage hydro) rate of \$0.0444.

ii. Contrast: High vs. Low Demand and Facilities Charges

Rates for larger commercial and industrial customers typically contain both a demand charge that varies with peak period demand (often measured as the highest 15 minutes in a month) and an energy charge based on kWh consumption (often differentiated by time of day). It is the sum of these, plus the customer charge, that makes up their cost of electricity service. If a utility collects a large amount of the revenue in the form of a demand charge and the remainder in a lower energy charge, the customer has a lower incentive to reduce usage through efficiency or on-site energy production in the remaining hours. If there is a goal to encourage energy conservation, it is better to concentrate costs into the energy charge, including TOU elements, than in the demand charge.

Figure 37 compares two utilities with very different approaches to dividing the rate between the demand charge and energy charge. Even though their overall revenue per kWh is about the same, it is easy to see that the high demand charge could suppress energy conservation efforts once the peak demand for the month has been established.

The Pedernales energy charge is 58 percent higher than that for the New Mexico cooperative; at a conservative long-run elasticity of -0.50, it would be expected to produce about 21 percent lower electricity consumption – for the very same overall rate level.⁶⁷ The lower energy charge leaves the New Mexico cooperative with some need to manage its peak demand during extreme hours – a

Figure 36

BC Hydro Rolling Baseline Large Commercial Rate	
Basic Charge	\$0.1853 per day
Demand Charge	<ul style="list-style-type: none"> • \$0.00 per kW for first 35 kW • \$4.51 per kW for next 115 kW • \$8.66 per kW for remaining kW
Energy Charge	<p>Part 1:</p> <ul style="list-style-type: none"> • \$0.0872 per kWh for last 14,800 kWh • \$0.0444 per kWh for remaining kWh up to baseline <hr/> <p>Part 2:</p> <ul style="list-style-type: none"> • \$0.0668 per kWh for usage up to 20% above baseline • \$0.0668 per kWh for savings down to 20% below baseline (credit) • Usage or savings beyond 20% of baseline are based on Part 1 prices

<https://www.bchydro.com/accounts-billing/customer-service-business/business-rates-overview/business-rates-prices.html> Accessed November 6, 2011

67 Elasticity is measured on a one-percent increment; the Pedernales energy charge is 58 percent higher than the New Mexico coop energy charge. It takes 46 1-percent increments to add up to a 58-percent increment. If a half-percent reduction in usage (in response to a 1-percent increase in price) is compounded 46 times, usage declines to 79 percent of the original value. $1.01^{46} = 1.58$; $0.995^{46} = 0.79$, or a 21-percent reduction in energy use based on an elasticity of -0.5.

Figure 37

Comparison of Two Rural Electric Cooperative Rates <i>One with High Demand Charge, One Low Demand Charge</i>		
	Pedernales Electric Cooperative	Central NM Electric Coop
Customer Charge	\$150.00	\$30.00
Demand Charge	\$3.92	\$18.32
Energy Charge	\$0.103	\$0.065
Average Cost/kWh	\$0.118	\$0.117
<i>Average cost based on 100 kW at 50% load factor Typical of small supermarket or 50,000 sf office building</i>		

problem best addressed with a critical peak price or other dynamic pricing tool, than with a bludgeon of a demand charge at \$18.32/kW/month applied to the customer's non-coincident peak demand.

D. Industrial

Industrial customers use electricity differently from other users: it is a factor input to the cost of production, and is methodically traded-off against alternative fuels, efficiency alternatives, and can even be a determinant of where industries are located. For example, aluminum smelters, one of the most energy-intensive industries, have migrated to distant regions of the world (Siberia, Mozambique, Suriname, Bahrain) in search of low electricity prices.

This paper does not address industrial pricing in great detail, because we believe it is too region- and resource-specific to provide general guidance. However, we will discuss four examples of industrial pricing that have had noteworthy impact.

i. Washington Real-Time Pricing (1996-2000)

In 1996, industrial customers of Puget Sound Energy, the largest electric

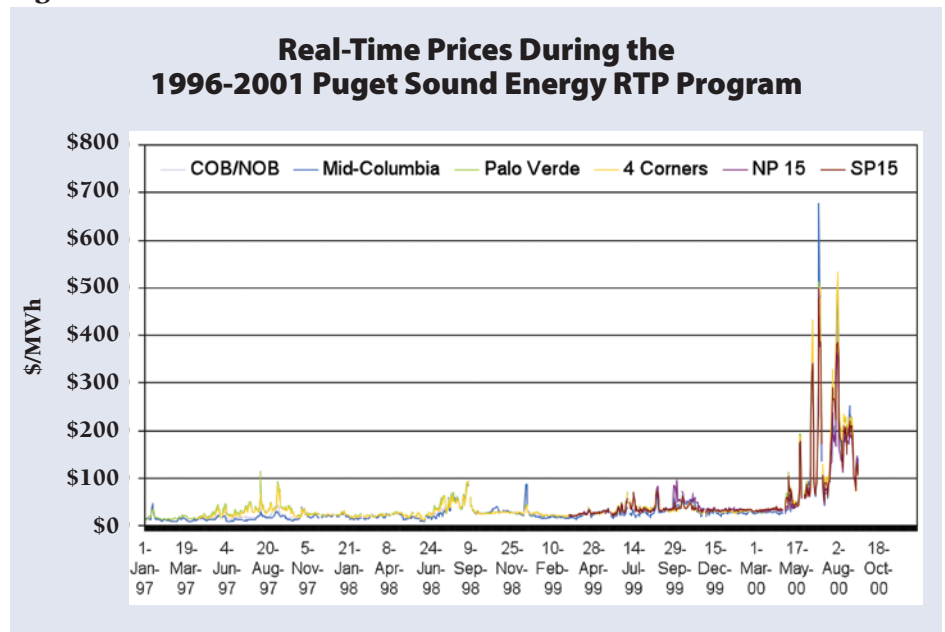
utility in Washington State, requested access to wholesale market pricing for electricity. The approach that was approved had three key elements:

- a) a transition charge for three years, during which time they paid a portion of the cost for stranded utility generating capacity until it could be absorbed by growth in usage by other customers;
- b) a delivery charge based on the cost of transmission services; and
- c) a daily price for on-peak and for off-peak power, based on day-ahead wholesale prices at the largest regional trading hub for electricity.

For the first three years, wholesale market prices were significantly lower than the costs embedded in retail rates, and the customers saved millions of dollars. In the fourth year, the western United States suffered a drought that reduced hydropower availability and put extreme pressure on natural gas supplies to provide relief generation, generally known as the California Energy Crisis of 2000-2001. Wholesale market prices soared to previously unknown levels. The customers, fully exposed to market prices, took drastic steps to adapt, including renting on-site diesel generators and curtailing operations. One major industrial facility, the Georgia-Pacific pulp and paper mill in Bellingham, WA, did not survive the economic impact of the power crisis, and closed permanently.

Eventually, in October of 2000, the customers

Figure 38



approached the Washington Utilities and Transportation Commission for regulatory relief, which was granted in the form of permission to enter into long-term contracts for power with non-utility suppliers, a form of open access not available to other retail customers.

Experience in regions providing open access to industrial customers suggests that some large users will choose a fixed-price plan over a dynamic rate, because the stability of cost allows them to make reasoned business decisions. An industry making sales commitments at contract prices for delivery months or even years ahead may prefer to “lock in” as many cost drivers as possible, including power supply costs.

The lesson learned from this experiment is that even large customers may need the ability to access power at cost-based prices to be economically stable and remain competitive. This can be done through cost-based utility pricing, or, where markets are used for power supply, the ability to enter into long-term contracts or to hedge power prices financially.

ii. Georgia Power Baseline-Referenced RTP

Georgia Power is a large investor-owned utility with a significant industrial base. For more than ten years, it has offered these customers a real-time pricing option. This is characterized as “baseline-referenced,” because customers only experience real-time prices for deviations in their usage (up or down), not for the total usage. The mechanism has the following characteristics:

- a) A customer baseline is established for each participating customer;
- b) Usage at the baseline is priced at a price determined through regulation, based on the utility cost of service;
- c) The customer is given notice of day-ahead prices; and
- d) Deviations from the baseline usage are charged or credited at the real-time price.

In essence, the customer “subscribes” to power at a regulated price, and then can consume greater or lesser amounts at a real-time price.⁶⁸ These tariffs have proven acceptable, and in 2011 became the standard tariff for large-use customers. An option to choose a fixed-price tariff is available after three years on a real-time rate.

iii. China Output/Unit-Based Curtailment

In 2010 and 2011, China experienced a shortfall of electricity supply in some regions. As a result, it has been forced to curtail electricity to some customers. One method China has used is to curtail industrial facilities in reverse order of electricity usage per unit of output. This has the effect of maximizing industrial output given a constrained supply of electricity, consistent with China’s overall economic policy.

iv. BPA Large New Single User Rate

The Bonneville Power Administration (BPA) is a US federal agency that markets federal power from hydroelectric dams, and augments that power with purchases from nuclear, wind, and other regional generating resources. It sells most of that power at wholesale to more than 100 public utilities and electric cooperatives.

The amount of power available from the low-cost hydro facilities is limited, and augmenting the power supply to serve growing demands means relying on much more expensive resources. When the US Congress gave BPA expanded authority to acquire power and serve growing needs, it limited the availability of the low-cost resource pool and explicitly did NOT include service to “large new single loads,” which were defined as any single facility increasing usage by more than 10 megawatts in a single year. Load growth at existing industries slower than 10 megawatts in a single year, or new industrial installations using less than 10 megawatts initially, are exempt from this.

BPA wholesale rates are complex, changing from month to month, and vary by time of day. Figure 39 compares the average wholesale rate charged by BPA to utilities for their general requirements, and the average rate charged for “New Resources” to serve those loads subject to the New Large Single Load policy.

Figure 39

Bonneville Power Administration Average Wholesale Rates	
	\$/kWh
Priority Firm Tier 1	\$0.0327
New Resources	\$0.0695

68 Georgia Real Time Pricing Day-Ahead With Adjustable CBL Schedule “RTP-DAA-4.”

E. Connection Charges

A few utilities have used connection charges for new customers to stimulate energy efficiency. This is an option that has great promise, because it places a cost burden at the time of new construction when efficiency opportunities are most cost-effective. Builders often make the decisions about building envelope efficiency and initial appliances at the time of construction, but the occupants of those buildings generally pay the energy bills. Connection charges directed at energy efficiency can be compelling to builders – if an investment in efficiency can reduce a utility connection charge, the “first cost” of an efficient building may be lower than the cost of constructing and connecting to the grid a less efficient building.

i. Indonesia PLN Capacity-Based Charges

PLN has a connection fee schedule tied to the installed kVA of the electric panel. As with PLN’s retail rates, customers desiring larger panel connections pay much larger fees to connect service. The lowest level of connections of 450 VA (~watts) is generally known as the “social tariff” and is paid for with government appropriations, to extend electricity service to near-universal coverage. Everything above the threshold level carries a hefty connection charge, linked to the panel size. A more efficient structure needs a smaller electrical panel.

The charge for customers exceeding the 450-VA threshold is based on the full costs of distribution system capacity, including substations, circuits, and line transformers.

ii. Idaho Feebates

In 1980, the Idaho Public Utilities Commission approved a “feebate” structure for the Idaho Power Company. This imposed a \$50/kW connection charge for new homes and offered an incentive rebate program for installation of measures that would achieve energy efficiency savings above and beyond applicable building codes. The rebates were available for insulation, improved windows, and high-efficiency heating and cooling systems. Builders were able to get rebates from the fund created by the connection charges.

At the time, most homes had connected loads in the range of 20 to 40 kW, whereas highly energy-efficient

homes required only 10 kW of connected panel capacity. A builder could save up to \$1,500 on the connection charge for a new home by installing above-code measures, and receive rebates of up to \$2,000 as well.

This program was discontinued by court order, ruling that the regulatory commission had exceeded its authority by entering into the area of “regulating” building energy efficiency. Idaho has since adopted the current International Energy Conservation Code, which provides for a high standard of efficiency.

iii. Mason County Code Substitute

Mason County is a rural county in Western Washington, about 50 miles southwest of Seattle. Electricity is provided by Mason County Public Utility District, an independent government agency with authority to provide water, sewer, electric, and communication services.

In 1989, many communities in Washington adopted improved energy efficiency standards for new residential buildings, but the general government authority of Mason County was not willing to adopt the regional model standard. The Public Utilities Department (PUD) wanted to achieve the energy efficiency target, and adopted an alternative approach. Builders that met the regional model standard received a rebate of up to \$2,000 per home. Builders that failed to meet the regional model standard were required to pay a \$2,000 connection fee per home.

The incremental cost of meeting the regional model standard was about \$3,000 for improved insulation, ventilation, and glazing. Builders quickly ascertained that their total out of pocket expense would be lower if they implemented the regional model standard (\$3,000 in costs less a \$2,000 rebate for a net of \$1,000) than if they did not meet the standard (\$2,000 connection charge). Compliance was over 90 percent within a few months.

A state association of mobile home manufacturers challenged the connection charge in federal court, arguing that efficiency standards for manufactured housing was regulated by federal law, which pre-empted local regulations. The trial court ruled that Mason PUD had exercised its rate-making authority in setting a higher price for service to less efficient homes, but had not overstepped its authority by refusing to serve a home that met the (more lenient) federal efficiency standard.

12. Recommendations and Conclusions

Implementing pricing reform is a long and difficult task for participants in the utility regulatory process. As reflected in the long list of valued examples and practices presented in this paper, the prescription for sound pricing can only be framed in broad terms. Undertaking such reform should be approached with a long-term view and political pragmatism.

We offer here some key observations on techniques that can be effective and can achieve constructive and lasting reform. Not all of these tactics will be appropriate for every country or for every regulatory authority.

A. Be Forward-Looking and Focus on the Long-Term

First and foremost, participants in the process focus on the long run, on the broad objectives of pricing policy, on its effects on consumers, utilities, and the environment, and on the costs and benefits of alternative rate structures. New buildings and new appliances last a very long time, and securing a pricing framework that encourages efficiency when investment decisions are made can provide lasting benefits.

Some jurisdictions set utility rates based on average or embedded cost, and some set rates based on marginal cost. Forward-looking LRM C should be the foundation for traditional pricing.⁶⁹ The difference can be huge, and LRM Cs are generally higher (often by quite a bit) than average embedded costs or SRM Cs.

In the short run, generating capacity does not change, but increased demand can cause transmission congestion, which can drive up short-run marginal transmission costs. In the long run, most utilities incur costs higher than their current average costs,

so LRM Cs (where all costs are considered variable) can be much higher than the average cost of existing resources upon which regulated prices are traditionally based.

When measuring LRM Cs, it is important to consider not only power supply costs (to include externalities), but also transmission and distribution capacity costs. All of these have capacity-related elements, and the load factors of different end uses will cause different levels of cost to be incurred. For example, residential lighting and appliances

Figure 40

Embedded and Marginal Costs <i>Illustrative (Not From a Specific Utility)</i>			
	Residential	Low-Income	Discount
Load Factor			
<i>kWh/kW</i>			
Generation Capacity \$/kW	\$100.00	\$ -	\$150.00
Generation Energy \$/kWh	\$0.03	\$0.05	\$0.06
Transmission Capacity \$/kWh	\$50.00	\$10.00	\$100.00
Distribution Capacity \$/kW	\$50.00	\$ -	\$100.00
\$/kWh for Appliances			
70% Load Factor			
<i>kWh/kW: 6,132</i>			
Generation Capacity	\$0.016	\$-	\$0.024
Generation Energy	\$0.030	\$0.050	\$0.060
Transmission Capacity	\$0.008	\$0.002	\$0.016
Distribution Capacity	\$0.008	\$ -	\$0.016
Total Cost	\$0.063	\$0.052	\$0.117
\$/kW for Air Conditioning			
20% Load Factor			
<i>kWh/kW: 1,752</i>			
Generation Capacity	\$0.057	\$-	\$0.086
Generation Energy	\$0.030	\$0.050	\$0.060
Transmission Capacity	\$0.029	\$0.006	\$0.057
Distribution Capacity	\$0.029	\$-	\$0.057
Total Cost	\$0.14	\$0.06	\$0.26

69 For a fuller discussion of this, see Weston, 2000, pp. 22-24 and Appendix 1.

have relatively high annual load factors (stable use all year long), whereas residential heating and cooling have low annual load factors (concentrated during relatively short periods).

Figure 40 compares illustrative marginal costs and shows how they translate into a basis for an end-block rate that separates lights and appliances (average load factor 70 percent) and air conditioning (average load factor 20 percent). The bottom line is that, given the assumptions below, the LRMC for serving appliances is about \$0.12/kWh, while that for serving air conditioning is about \$0.26/kWh.

Low load factor end uses have higher average costs than high load factor end uses. The same difference in average costs would also be apparent if residential consumers were subject to the same type of rate design as general service customers, with separate demand charges. The cost of power to serve different residential end uses would be dramatically different from the “average” prices typically applied in flat residential rate designs: space conditioning would pay much higher average prices than other residential usage.

B. Recover Costs on Usage-Sensitive Rate Elements

If there is one important message in this entire paper, it should be that high monthly fixed charges are a poor method to recover utility system costs, whether they are distribution facilities or generation plant. Advocates of this type of rate argue that the costs are “fixed” and so they should be recovered in fixed charges.

The electricity industry is capital intensive. As such, most costs are indeed fixed for a period of time. They are, however, also usage sensitive and should be priced to reflect this usage sensitivity. Indeed, usage-based pricing is typical of most industries. Oil refineries have billions of dollars in fixed costs, but recover those costs in the price per unit (gallon, liter) of fuel sold. Hotels have millions of dollars in fixed costs, but recover them in the prices for each room-night rented (the smallest increment in which they sell service, just as a kWh is the smallest unit in which electric utilities sell service). Auto rental companies have large fixed costs, but recover them in the prices they charge by the day and week.

Utilities are really not all that different. In most parts of the world, cellular telephone companies offer both

“subscription” pricing for plans, and “prepaid” pricing for small users. While large users may subscribe to an unlimited plan costing \$50/month or more, small users often opt for per-minute service.⁷⁰ The cost of having a mobile phone, a phone number, voicemail, and the ability to send and receive text messages is only a few dollars per month, with modest per-minute fees for actual usage. Consistent with competitive industries and sound economic principles, electricity should be priced to recover costs from usage-sensitive components.

C. Empower Consumers to Respond Effectively to Rates

Utility rates will only generate the desired response if consumers understand the rate. A rate design that seems “perfect” to an economist may be gibberish to the typical customer. First, as alluded to earlier, larger customers can and should understand more complex rates. Second, rates should ideally be kept simple, and when complexity is a necessary aspect, it should be offered as an optional service offering. Any residential rate more complicated than a seasonally differentiated two- or three-block rate requires a considerable effort in consumer education, and still may not be effective.

Effective communications through the customer bill is also important. Many utilities do not print the full and combined price for service on their bills. Without this information, consumers may not understand how the various elements of the rate fit together. In Section 5 we showed an example of a detailed bill by rate element, and a “rolled up” bill showing the bottom-line consumer effect. The latter is information the consumer can actually use to decide whether to use more electricity, to invest in more efficiency, or to do without.

D. Consider Some Form of Dynamic Pricing as an Optional Service

Recent research on dynamic pricing is showing that consumers can reduce and alter usage for short periods of time (i.e., provide customer demand response) in response

70 In the United States, Tracfone offers service for as little as \$8/month, with 100 minutes/month of service on an annual plan. In other countries, pay-per-minute service is available at even lower prices.

to either sharply increased prices over such periods or utility-controlled loads, like the air conditioner control program described in Section 9. Such short-term response has also demonstrated persistence.⁷¹ These observations indicate that customers can defer consumption until costs and prices moderate.

Dynamic pricing involves market or real-time elements that cannot be fully anticipated in an ex ante tariff structure. Usually the dynamic component of the rate is embedded in the price signal itself (e.g., real-time pricing) or the timing of the event (e.g., critical peak pricing). These are short-term price signals that can also be received by consumers as longer-term price signals if pricing events recur in a reasonably predictable manner and the consumer is well informed. There are three ways in which a dynamic price signal may send a long-run, or at least longer-run, marginal cost signal that is distinct from that which is possible using only traditional pricing, especially the average price signal that is typically passed to mass market consumers.

First, dynamic pricing can be responsive to change. Changing market circumstance, system conditions, and

price levels may be one of the most persistent features of wholesale power markets in the future. Consumers can hedge uncertainty by purchasing more efficient or more flexible (e.g., with a heat/cooling storage component) end-use devices.

Second, dynamic pricing can also be structured to reduce peak demand and target peak energy prices. When it is used for the purpose of peak reduction, it provides a dynamic price signal that communicates one aspect of system reliability, the capacity requirements of the system during peak load demands.

Third, dynamic pricing can be coupled to more traditional forms of rate design discussed earlier (e.g., inclining block rates) to create a consistent message about long-term costs.

That said, and as noted previously, some foresight is required in introducing dynamic pricing, especially for mass market customers. Consumers must be appropriately empowered. Large industrial customers already possess complex meters that record usage and have to be read and interpreted periodically. Modern advanced metering infrastructure permits interval metering of all consumers. This enables the use of responsive time-differentiated pricing for all customer classes. These rates can be complex and should be available to consumers who can understand and respond to them. Special care in offering such rate plans to small residential and commercial consumers who may have more limited ability to interpret or react to them. As discussed in the companion paper on dynamic pricing, demand response increases at higher price levels, but at diminishing returns to price multiples.⁷² Pricing of that type should not be implemented without effective education, support, and empowerment.

Wholesale Pricing and System Adequacy

In restructured utility systems, market clearing prices are often the basis of time-differentiated prices. If utility system resources are adequate, these do not rise above the fuel and variable operating costs of the most expensive resources (often oil-fired peaking units). If resources are in short supply, prices spike sharply, because it is impossible to add new capacity in the short run. This is what happened during the California energy crisis of 2000-2001. Some analysts approve of this, on the logic that those price spikes should be reflected in retail prices and thus simultaneously signal consumers to reduce usage and reward producers for having capacity available. Others believe that “capacity payments” should be made to producers, thereby ensuring adequate capacity and preventing price spikes. From a rate design perspective, whichever approach is used, the costs (either capacity payments or price spikes) should be reflected in the price for electricity during extreme loads.

E. Complement Effective Price Signals with Effective Policies and Initiatives

Electricity is a necessity for modern living. Most consumers who have electric service will pay a very high price to keep it flowing to their televisions, their lights, and their refrigerators. Evidence from Alaska, Hawaii, the Caribbean, and other remote places with diesel-generated

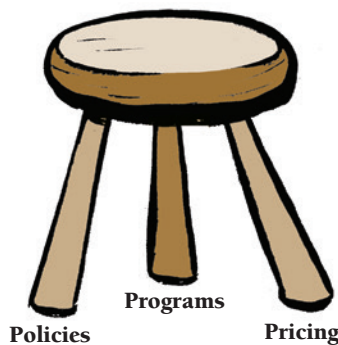
71 Faruqui et al., 2012 at page 31.

72 Faruqui et al., 2012, at pages 30-31.

electricity that costs three or even five times continental prices demonstrates this – energy inefficiency is nearly as prevalent in high-cost areas as in low-cost regions. Although there is definitely price elasticity (change in consumption in response to a change in price), most studies show it is quite low.⁷³ Prices are a relatively blunt instrument to influence energy consumption.

Even a doubling of rates will likely only produce a relatively small change in consumption in the short run, because in the short run, people do not replace appliances, insulate buildings, or replace industrial motors.

On the other hand, investments in energy efficiency can very quickly produce much larger savings. Pricing is not a substitute for utility and government energy efficiency education, incentives, codes, standards, and rebate programs. But efficient pricing, with incremental prices reflecting long-run incremental costs, can increase people’s willingness to participate in utility efficiency programs, to invest in energy efficiency measures, and to constrain their usage where it is uneconomic. **Pricing** does matter – but it is not a substitute for good **policies** (such as appliance efficiency standards) and good **programs** (such as utility energy efficiency grants and loans). Together, these three form a stable platform for energy efficiency achievement. Separately, none will accomplish more than a small fraction of the economic potential for efficiency.



F. Summary

The focus of this paper has been on rate design using conventional meters. Rate design for vertically-integrated utilities generally involves an administrative determination of bundled retail electric prices including production, transmission, and distribution costs. For restructured utilities, generally only the delivery costs are considered and only delivery prices administratively determined. This report addresses rate design in the context of conventional metering technology. The vast majority of retail customers around the world rely on conventional meters and are subject to rate design proceedings.⁷⁴ The rate designs that are associated with conventional meters are likely to continue as a dominant feature of retail service for the foreseeable future. There is a rich body of progressive practices and experiences for regulators and policymakers who are interested in fostering sound and sustainable pricing practices in the power sector.

The discussion above identified a wide range of (largely) retail service arrangements that represent valued practices that have been developed for application in the different regions of the world.

73 See Faruqui, 2008.

74 Not all electricity prices are set by regulators or an oversight body through administrative determination. Some portions of unbundled electricity prices are determined in the context of a competitive market through competitive retail providers.

13. Appendix A

Calculation of Estimated Elasticity Effect of Three Residential Rate Designs

The purpose of this appendix is to show the expected impact on total residential electricity consumption of three alternative rate designs, all producing the same level of expected revenue before elasticity effects. The result of this illustrative calculation is that a hypothetical inclining block rate design would reduce consumption by about 8.6 percent compared with a flat rate, whereas an SFV rate design would increase consumption by about 7 percent. These are all dependent on some important assumptions that will vary from utility to utility, country to country, and region to region, but provide an indication of the impact that rate design can have on usage.

About Elasticity

Elasticity measures the change in quantity demanded with respect to the price for a commodity. There are several different measures of elasticity; this analysis is concerned with Price Elasticity of Demand, which is the percent change in quantity demanded in response to a percent change in the price. There is also Income Elasticity of Demand, which measures the change in quantity demanded as consumer income rises, and Cross-Elasticity of Demand, which measures the change in the demand for product B (say, natural gas) in response to a change in the price of product A (say, electricity).

The price elasticity of demand is a measure of the percent change in quantity demanded as a result of a 1-percent change in price. Technically this is called *point elasticity*, because it measures elasticity at a single point along the demand curve. In order to measure the elasticity impacts from a rate design change, we need to know how many 1-percent increments any given change in rates contains. Because the 1-percent changes are compounded, and the elasticity is compounded,

it is not as simple as “at -0.5 elasticity, a 20-percent change in price will cause a 10-percent change in the quantity demanded.” There is a measure, known as arc elasticity, that measures the percent change in quantity demanded over a large incremental change in price, but it is derived from the calculation of point elasticity.

Our Illustrative Utility

We start with an assumed utility with 50,000 residential consumers, using a total of 50 million kWh per month, an average of 1,000 kWh/month/consumer. It has a flat rate design, consisting of a \$5.00/month customer charge, plus an energy rate of \$0.085/kWh. We want to measure the expected elasticity effect of alternative rate designs.

The first alternative is an inclining block rate with a \$5.00 customer charge, and three energy blocks priced at \$0.07, \$0.10, and \$0.14. The third is an SFV with a \$35 customer charge and a \$0.05/kWh. Both are designed to produce the same total revenue, before elasticity impacts.

All three rate designs produce identical bills for the average customer using 1,000 kWh/month, but for customers with above or below average usage, the results are very different.

In order to estimate the elasticity effect of the inclining block rate design or the SFV rate design compared with the flat rate design, we need to know two things. First, we need

Figure A-1

Three Basic Rate Designs			
Rate Designs	Flat Rate	Inclining Block Rate	Straight Fixed/Variable Rate
Customer Charge \$/month	\$5.00	\$5.00	\$30.00
First 500 kWh/month	\$0.085	\$0.070	\$0.060
Next 500 kWh/month	\$0.085	\$0.100	\$0.060
Over 1000 kWh/month	\$0.085	\$0.140	\$0.060

Figure A-2

Bill Impact of Three Rate Designs			
Bill Analysis	Flat Rate	Inclining Block Rate	Straight Fixed/ Variable Rate
250 kWh	\$26.25	\$22.50	\$45.00
500 kWh	\$47.50	\$40.00	\$60.00
1,000 kWh	\$90.00	\$90.00	\$90.00
1,500 kWh	\$132.50	\$160.00	\$120.00
2,000 kWh	\$175.00	\$230.00	\$150.00

to know the expected price elasticity of demand. Second, we need to know the distribution of customer usage, so we can know how much energy is sold to customers whose usage ends in each block.

Estimates of the short-run price elasticity of demand prepared by many analysts range from -0.02 to -0.50 . For this example, we will assume that the short-run price elasticity of demand is -0.25 , meaning that a 1-percent increase in price will lead to a 0.25-percent decrease in the quantity demanded. This is simply an example for purposes of illustration; it is in the range of likely results, but we do not assert here that it is the “correct” factor for any particular utility or consumer. We assume it applies uniformly to any change in price. Some analyses show that elasticity is greater for higher levels of residential usage.

The next thing we need to know is the distribution of usage of customers, so we can estimate how many will see a lower marginal price under the three-block rate, and how many will see a higher marginal price. This is derived from one actual utility’s customer base, but is simply illustrative.

Figure A-3

Distribution of Customers by Usage Level					
	Customers	kWh		Average use	Total kWh
	Ending in Block	Ending in Block	Usage Through Block		
0-500	5,000	1,250,000	22,500,000	250	1,250,000
501-1000	25,000	6,250,000	10,000,000	750	18,750,000
1001+	20,000	10,000,000		1,500	30,000,000
Total	50,000	17,500,000	32,500,000		50,000,000

Figure A-4

Residential Revenue With Flat Rate			
	Units	Price	Revenue
Customer Charge	50,000	\$5.00	\$250,000
Energy Charge	50,000,000	\$0.085	\$4,250,000
Total			\$4,500,000

For this utility, out of 50,000 total customers, only 5,000 have usage of less than 500 kWh/month, whereas 20,000 have usage in excess of 1,000 kWh/month, as shown in Figure A-3.

With the flat rate design, this utility will collect \$4.5 million in residential revenue per month.

Computing Elasticity Effects

Point elasticity is reasonably accurately measured as the percent change in quantity demanded with respect to a 1-percent change in price. So the next step is to determine how many 1-percent increments in price are represented by each of the alternative rates, and then apply the elasticity factors to them.

First Block Elasticity

The change from a flat rate to an inclining block rate results in a decrease in the rate for the first block of residential usage. It is therefore expected to cause an increase in usage by the consumers whose usage does not exceed the first block, because these customers will see the lower price as their incremental rate for incremental usage. As we know from Figure A-3, however, there are only 5,000 of these customers (using an average of 250 kWh/month), and their total consumption is only 2.5 percent of total consumption.

So while 10 percent of customers will likely use more electricity, they will not use very much more electricity. The calculation below shows how much the expected increase in usage will be.

The first step of this is to determine the percentage reduction in the block rate. The change from \$0.085/kWh to \$0.07/kWh is an 18-percent reduction. Next comes

the iterative process of measuring how many 1-percent decrements this is, which works out to 17 increments (1.01 raised to the 17th power = 1.18). Next, we measure the percentage decrease in the quantity demanded, by applying our assumed elasticity factor of -0.25. 1.0025 raised to the 17th power equals 104%, meaning that we would expect an 18-percent decrease in price to result in a 4-percent increase in consumption. Applying this to the original consumption level of 1,250,000 kWh by the customers in this group – those using less than 500 kWh/month – yields an increase of 54,201 kWh/month as a result of decreasing the price in the first block.

Second Block Elasticity

The customers whose usage ends in the second block, those using 500 to 1,000 kWh/month, will all enjoy the benefit of the decreased price for the first block, but they will all see the increased second block price as their marginal price. This is a much larger group of consumers – 25,000 – and they use a much larger amount of electricity, so the effects are much larger.

Although the first block decreased \$0.015/kWh, from \$0.085 to \$0.07, this second block has increased by \$0.015, to \$0.10/kWh. This is also an 18-percent increase, meaning also 17 iterations of a 1-percent change. But this time it is a downward effect, so we take 0.9975 and raise it to the 17th power, resulting in expected usage by this group of 96 percent (4-percent decrease). But because their usage is so much larger, this amounts to a 781,135 kWh/month decrease, some 15 times the increased usage estimated for the first block.

Third Block Elasticity

Customers whose usage ends in the third block face a more dramatic increase in their marginal price, from \$0.085/kWh to \$0.14/kWh. This is an increase of 65 percent, which one would expect to produce a much larger effect. And with 20,000 consumers, using a total of 60 percent of total energy, the impact is quite significant.

Here we see that to achieve a 65-percent increase in the price amounts to over 50

Figure A-5

Elasticity Effect of Inclining Block Rate on Customers Ending in First Block			
Block 1 Effect			
Usage Subject to Increased Consumption			1,250,000
Change in Rate %	\$0.085	\$0.070	-18%
1% Increments	1.01	17	18%
Elasticity Factor	100.25	17	104%
Increase in Usage			54,201
Percentage Increase			4%
Usage of customers ending in block after Elasticity			1,304,201

Figure A-6

Elasticity Effect of Inclining Block Rate on Customers Ending in Second Block			
Block 2 Effect			
Usage Subject to Decreased Consumption			18,750,000
Change in Rate %	\$0.085	\$0.100	18%
1% Increments	1.01	17	18%
Elasticity Factor	99.75	17	96%
Increase in Usage			(781,135)
Percentage Reduction			-4%
Usage of customers ending in block after Elasticity			17,968,865

Figure A-7

Elasticity Effect of Inclining Block Rate on Customers Ending in Third Block			
Block 3 Effect			
Usage Subject to Decreased Consumption			30,000,000
Change in Rate %			65%
1% Increments	1.01	50.5	65%
Elasticity Factor	99.75	50.5	88%
Increase in Usage			(3,562,345)
Percentage Reduction			-12%
Usage of customers ending in block after Elasticity			26,437,655

incremental 1-percent increases. Applying the same elasticity of -0.25 means raising 0.9975 to the 50th power, resulting in an estimated 12-percent decrease in the quantity demanded, or more than 3.5 million kWh per month.

Combined Effect of Inclining Block Rate

The combined effect of the shift from a flat rate to an inclining block rate is the sum of the effect on the three blocks. First, a small increase in usage by the relatively small number of customers using less than 500 kWh; second, a moderate decrease in usage by 50 percent of customers whose usage ends between 500 kWh and 1,000 kWh/month; and finally, a fairly significant decrease by the largest users, those consuming over 1,000 kWh/month. Figure A-8 sums the result.

Impact of Straight Fixed/Variable Rate Design

The SFV rate design collects all costs except those expected to vary with usage in the monthly customer charge. It then has a very low per-kWh charge of \$0.06/kWh, based on what the utility would avoid in the short run if it reduced power production or purchases in response to lower sales (this is actually a complex calculation, because it must consider all costs that vary – including revenue-sensitive items like taxes and changes in line losses when loads change, and it must look at the marginal resources the utility would use or curtail, which will have above-average fuel and operating costs, because they will keep using the cheaper resources to serve the remaining loads).

The elasticity calculation, however, is much simpler, because all electricity is sold at a single (lower) price. Figure A-9 presents that calculation.

All of the 50,000,000 kWh of usage will see a reduction from the flat rate of \$0.085/kWh to the SFV rate of \$0.06/kWh, which is a 29-percent reduction in the unit price, offset by a 500-percent increase in the customer charge. This 29-percent reduction amounts to 25.5 incremental

Figure A-8

Combined Effect of Inclining Block Rate Design	
Total Original Usage	50,000,000
Increase by Customers Ending in First Block	54,201
Decrease by Customers Ending in Second Block	(781,135)
Decrease by Customers Ending in Third Block	(3,562,345)
Total Usage After Shift to Inclining Block	45,710,721
Total Reduction in Usage	(4,289,279)
Total Percentage Reduction in Usage	-8.6%

Figure A-9

Effect of Straight Fixed/Variable Rate Design			
Usage Subject to Increased Consumption	50,000,000		
Price with Flat Rate	\$0.09		
Price with SFV Rate	\$0.06		
Change in Price \$/kWh	\$0.03		
Change in Price %	29%		
1% Increments	1.01	25.5	29%
Elasticity Factor	100.25	25.5	107%
Increase in Usage	3,287,056		
% Increase in Usage	7%		

1-percent decreases in the price. Raising the elasticity factor of 1.0025 to the 25.5th power yields 107 percent, meaning a 7-percent increase in expected quantity demanded.

This stands in stark contrast to the inclining block rate, which was estimated to generate an 8.6-percent decrease in total consumption. Compared with typical estimates that 30 percent of energy consumption can be avoided with cost-effective energy efficiency measures, this range of +7 percent or -8.6 percent is equal to about half of the potential efficiency savings from cost-effective programmatic retrofits. The point is that the consumption impact of rate design is very significant.

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