LBNL-39845
UC-1321

Transmission Pricing and Renewables: Issues, Options, and Recommendations

Steven Stoft, Carrie Webber, and Ryan Wiser

Environmental Energy Technologies Division
Ernest Orlando Lawrence Berkeley National Laboratory
University of California
Berkeley, California 94720

May 1997

The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Table of Contents

Acknowledgments

The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

We would like to thank reviewers Greg Basheda (DOE), Andy Brown (Ellison and Schneider), Joe Eto (LBNL), Chuck Goldman (LBNL), Diane Pirkey (DOE), Richard Rosen (Tellus Institute), and Rich Scheer (Energetics).

Acronyms and Abbreviations

AWEA	American Wind Energy Association
BECo	Boston Edison Company
CCEM	Coalition for a Competitive Electricity Market
ConEd	Consolidated Edison of New York
CRT NOPR	Capacity Reservation Tariff Notice of Proposed Ruling
FERC	Federal Energy Regulatory Commission
LDC	Load duration curve
NUG	Non-utility generator
PGE	Portland General Electric Company
PG&E	Pacific Gas & Electric Company
POD	Point of delivery
POR	Point of receipt
PV	Photovoltaic
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
TCR	Transmission capacity reservations
WEPEX	Western Power Exchange
ZFC	Zero-fixed cost

Abstract

Open access to the transmission system, if provided at reasonable costs, should open new electricity markets for high-quality renewable resources that are located far from load centers. Several factors will affect the cost of transmission service, including the type of transmission pricing system implemented and the specific attributes of renewable energy. One crucial variable in the transmission cost equation is a generator's capacity factor. This factor is important for intermittent renewables such as wind and solar, because it can increase transmission costs several fold due to the traditional use of take-or-pay, capacity-based transmission access charges.

This report argues that such a charge is demonstrably unfair to renewable generators. It puts them at an economic disadvantage that will lead to an undersupply of renewable energy compared with the least-cost mix of generation technologies. We argue that congestion charges must first be separated from the access charges that cover the fixed cost of the network before we can design an efficient tariff. We then show that, in a competitive market with a separate charge for congestion, a take-or-pay capacity-based access charge used to cover system fixed costs cannot be justified on the basis of peak-load pricing. An energy-based access charge, on the other hand, is fair to intermittent generators as well as to the usual spectrum of peak and base-load technologies.

This report also reviews other specific characteristics of renewables that can affect the cost of transmission, and evaluates the potential impact on renewables of several transmission pricing schemes, including postage-stamp rates, megawatt-mile pricing, congestion pricing, and the Federal Energy Regulatory Commission's "point-to-point" transmission tariffs.

Executive Summary

The electricity industry, historically dominated by regional monopolies, is moving into an era of greater competition. This transformation, popularly termed restructuring, involves all aspects of the industry, including transmission. This report reviews the current state of transmission pricing, including the Federal Energy Regulatory Commission's Order 888 and Capacity Reservation Tariff Notice, current and proposed transmission pricing schemes, and current rates. We then examine the effects of different pricing schemes on different types of generators, focusing specifically on renewable generators. In particular, we consider the effect of charging for network access based on energy rather than capacity.

The main findings from our analysis are as follows:

- Factors that may increase a generator's transmission cost include limited flexibility in choosing a facility's location, greater distance from load, coincidence with peak load, low capacity factor, and intermittence. Most types of renewable generation experience at least some of these problems.

- "Take-or-pay" firm capacity reservation charges penalize low capacity factor intermittent generators, which include wind and solar generators. A take-or-pay contract is one in which the generator must pay for the capacity reserved whether he uses it or not.

- Although alternatives to take-or-pay contracts exist, they are either expensive or impractical when output is variable and unpredictable, as it is for intermittent renewables (wind and solar).

- The most commonly used transmission tariffs fail to separate congestion charges from charges used for fixed cost recovery ("access charges").

- Congestion charges must be separated from network access charges to achieve economic efficiency.

- In a competitive market with separate congestion charges, collecting fixed costs through a capacity-based access charge is demonstrably unfair to intermittent renewable generators and results in too little renewable generation compared with the least-cost technology mix.

- In a competitive market with separate congestion charges, an energy-based access charge leads to the least-cost mix of generation technologies.

- Regulators should consider instituting congestion pricing and using an energy-based access charge to recover fixed costs.

1 Introduction

As part of the national trend toward a more competitive electricity industry, popularly termed "restructuring," all interested parties are being granted access to the transmission grid. In fact, the Federal Energy Regulatory Commission (FERC) has mandated "open access" to the grid and specified that charges for this access be equitable and economically based. FERC's guidelines allow many possible rate systems for transmission services. Because of this, renewable electricity generators (and all other parties) have an interest in influencing the design of these rate structures. Consequently, they also have a need to understand how these structures interact with their particular product as they bring it to market in the newly restructured environment.

Many transmission pricing systems are currently under consideration, including postage stamp, megawatt-mile, nodal, and FERC "point-to-point." This report develops a framework for determining the impact of transmission rate structures on renewable generators. We use that framework to draw some general conclusions regarding the effects of certain rate structures on four types of renewable generation, including geothermal, biomass, wind and large-scale solar.[1] Building on the work of Ellison, Brown, and Rader (1996), this analysis will show that certain structures favor certain types of generation and harm others systematically.[2] It will also show that these effects can amount to a large share of the cost of transmission.

Renewables possess specific attributes that can increase the cost of transmission for these resources. This study focuses primarily on intermittence combined with a low capacity factor. We also briefly discuss the effects of higher-than-average distance from load centers, location-dependence and coincidence with system peak.

The need for firm transmission capacity coupled with intermittence and low capacity factor turns out to be very costly under current pricing systems. These systems couple the purchase of "firmness" (guaranteed access to a certain amount of capacity) with the need to cover fixed costs of constructing the transmission grid. Firmness is purchased by reserving firm transmission capacity. This is done through take-or-pay arrangements, in which the purchaser must pay for the amount of capacity reserved, no matter how much is actually used. Intermittent/low capacity factor generators are at a disadvantage under take-or-pay contracts

---

1 We generally focus on renewables that provide bulk power and therefore require transmission service. We do not address distributed generation that does not require extensive transmission service and, in some cases, is actually used to offset transmission and distribution expansion needs.

2 Each generator is different, of course. The best rate structure for any particular generation project will depend on its location and operating characteristics, and may be different from what is best for that type of generation on average.

because they can use their reserved capacity only during their intermittent periods of operation, yet they must pay for the full reserved capacity for the entire reservation period.

Network fixed costs are currently recovered using the same capacity reservation charge as firmness. This unnecessarily inflates the cost of firm transmission capacity and penalizes intermittent/low capacity factor generators. By reducing the firm capacity reservation charge to cover congestion only and charging separately for fixed costs through a grid access charge, it becomes possible to consider alternative pricing structures for the access charge. In particular, we look at the effect of charging for network access based on energy rather than capacity.

By noting that congestion costs are marginal costs and that they exhibit the classic rate-making problem of being insufficient to cover the fixed costs of the transmission grid, we can use Bonbright's observation. "Some of the modern literature of rate theory approaches this problem by treating a rate as composed of two parts: a minimum rate, called a 'price,' and a surcharge, called a 'quasi tax.'" (Bonbright 1961, p. 302) Our solution will in fact be to use a congestion charge as a price and to design the access charge to minimize its distortionary "taxing" effects.

So, to compare capacity-based and energy-based charges in the context of a competitive energy market, we view them both as taxes.[3] All taxes cause distortions in behavior and thus inefficiencies.[4] Often it is found that the payer of the tax does not bear the full burden of the tax but is instead able to pass on much or all of it. In this case we find that most generators can pass on both types of access charge to consumers through higher prices. Intermittent generators, however, cannot pass on the full cost of a capacity-based access charge but can pass on an energy-based charge. The part of the capacity-based charge that falls on intermittent renewable generators inevitably causes a market inefficiency, one that is particularly unfair to these generators.

Because the access charges are usually passed through to loads, they also may cause distortions in consumption patterns and some inefficiency. This appears likely to be a little worse under the capacity-based charge.

The following three sections describe the dilemma for renewable generators in the current transmission environment and under some of the proposed transmission tariffs. Section 2 describes some current and proposed transmission pricing methods, including postage stamp, megawatt-mile, and congestion pricing, and discusses the current regulatory environment defined by FERC Order 888 and its Capacity Reservation Tariff Notice of Proposed Ruling

[3] This view does not imply any negative connotation, in fact, the access charge is completely analogous to a tax on gasoline that is used to pay the fixed cost of building highways.

[4] Unless the tax is on something with a sufficiently large negative externality.

(CRT NOPR). A summary of current rates and practices is provided. Section 3 discusses the special transmission issues for renewables, including financing constraints, capacity factor and intermittence problems, distance from load, locational flexibility, and coincidence with system peak. A numerical example illustrates how the combination of distance and low capacity factor can dramatically increase transmission costs for renewables under the current rate system. We then discuss the relative advantages and disadvantages of different transmission pricing methods for four types of renewable generators: solar, wind, biomass, and geothermal. Section 4 lists four specific alternatives for intermittent/low capacity factor generators operating in the current take-or-pay capacity reservation environment: (1) purchasing nonfirm transmission service, (2) purchasing firm contracts that match generation patterns, (3) selling back unused capacity, and (4) using a power marketer for firming. We then discuss alternatives to the current take-or-pay capacity reservation paradigm that could benefit renewables. These include proposals by Ellison et al. (1996), Rosen and Bernow (1994), and the American Wind Energy Association (Porter 1996).

Sections 5 through 7 contain our economic analysis of different forms of access charges. Section 5 discusses the flaw of the current system of combining congestion charges and access charges and argues that the two charges should be separated. The underlying assumptions for the analysis in Section 6 are discussed. Section 6 presents a model of a competitive market with a separate congestion charge. We find the efficient technology mix, and show that an energy-based access charge will not alter that mix, but a capacity-based charge will. In particular, a capacity-based charge will result in less intermittent renewable generation than the least-cost technology mix. Section 7 discusses the effect of the two types of access charge on congestion and on consumption. Section 8 presents our conclusions and directions for future work.

2 Background

The transmission restructuring debate involves many parties with competing interests. Economic efficiency, fairness, preserving and promoting clean generation technologies, and administrative ease are just some of the issues that have been discussed as restructuring efforts have moved forward. This section describes some of the pricing methods currently in use or under consideration, including postage stamp rates, megawatt-mile rates and nodal pricing. We then describe the current regulatory environment, defined by FERC Order 888, and look briefly at how transmission providers have complied with Order 888.

2.1 General Methods of Pricing Transmission

Two fundamental issues drive the design of transmission pricing schemes. The first is the existence of network fixed costs. Transmission providers must somehow recover these costs. The second is pricing for congestion. When there is sufficient transmission capacity on a line to satisfy the demands of all users of the system, the line is said to be uncongested. When the demand for transmission service exceeds the capacity of the line, some generators may be unable to obtain transmission service. If the price of transmission increases as the line becomes congested, transmission capacity will be allocated to those willing to pay the most for service. If not, capacity may be allocated inefficiently. Transmission pricing methods vary in how well they address these two issues, and many pricing proposals are under consideration.

Historically, firm transmission service has been sold based on capacity reservation. That is, generators pay for guaranteed access to a specified amount of transmission capacity. The generator must pay for the total capacity reserved no matter how much energy is transmitted. Such transmission contracts are often referred to as “take-or-pay.” We refer to this kind of transmission pricing scheme as capacity-based pricing (i.e., priced in $/MW). In contrast, energy-based pricing (in $/MWh) would charge only for the actual energy transmitted.

Capacity reservation handles congestion by restricting the amount of firm transmission service sold on the network. If congestion arises, nonfirm customers will be curtailed first. Firm customers are protected against curtailment under normal operation. Firm capacity reservation can be thought of as insurance against curtailment. Essentially, it should be the prepayment of expected congestion charges. By agreeing to pay the expected congestion charges, the generator protects itself against both curtailment and fluctuation in the congestion price.

Prior to Order 888, transmission pricing was dominated by postage stamp rates—flat capacity-based charges for network access. Less commonly used was contract-path pricing. This method identifies particular lines over which power could flow, and charges are based on grid miles with additional charges for facilities used (such as transformers). The problem with contract-path pricing is that "grid miles" do not accurately represent power flows. In a network, power does not flow along the shortest path from its point of entry to its final destination, nor can it be made to follow a particular contract path. Actual power flows are dictated by the laws of physics, and actual transmission can affect power flows far from the contract path. Some of the current crop of transmission pricing proposals directly address this flaw in contract-path pricing.

The various transmission pricing schemes currently in use or under consideration have very different implications for the market. Do the prices provide information about congestion? Will the fixed cost of the network be covered? Of particular interest to renewables: Are users charged for distance? How? Do users pay for energy or capacity? We describe three basic approaches to transmission pricing which represent the range of proposals and discuss the implications of each.

2.1.1 Postage Stamp

Postage stamp rates have been the most common transmission pricing approach. A postage stamp rate is a flat per kW charge for network access within a particular zone, based on average system costs. The cost for transmitting within the zone is independent of the transmission distance. Postage stamps are the most common type of transmission tariff.[5]

A generator transmitting to a load in a different zone would have to pay the postage stamp charges for the zone of origin and the zone of delivery, and also any intervening zones. This accumulation of zone access charges is often called "pancaking." Although transmission within a zone is independent of distance, longer distances increase the likelihood that more than one zone will be crossed, which would increase the total transmission cost.

Although postage stamp rates provide a way to recover the fixed costs of the network, they provide no information about congestion when used by themselves.

[5] Although it is convenient to classify rates as either postage stamp or contract path, in practice the distinction is not so clear cut. When a load contracts with a distant generator, it may be possible to specify more than one contract path between the two. These alternative paths may cross different jurisdictions and thus be subject to different accumulated postage stamp rates. Thus, for inter-regional flows, both systems come into play at once.

2.1.2 Megawatt Mile

Other types of rates explicitly reflect the fact that the cost of transmission depends on the distance the power is transmitted and how much power is transmitted. Traditional contract-path pricing identifies a particular transmission path over which the transmitted power *could* flow. Such rates do not price transmission accurately because they fail to take into account the total effects of the transaction on the network. Flow-based pricing schemes, such as megawatt-mile pricing, were developed as an alternative to contract-path pricing. Megawatt-mile pricing generally involves using load flow analysis to model the power flows on the transmission network to determine transmission distance (see Wakefield et al. 1995, and Mistr 1996). These distances, if computed correctly, more accurately reflect the impact of a transmission agreement on the system.[6] The cost of transmission per megawatt-mile is the total cost averaged over megawatt-miles of usage. Used alone, MW-mile rates provide no information about congestion.

2.1.3 Congestion Pricing

Neither postage stamp nor megawatt-mile pricing provides any information about congestion. Transmission capacity is allocated efficiently if it is sold to parties with the highest willingness to pay. If prices do not increase as congestion increases, transmission capacity may be allocated so that it is worth less to those who have it than to those who do not.

Transportation theory dictates that the price of a good in a set of competitive marketplaces should differ only by the cost of transportation between the markets and the economic cost of congestion. In transmission markets, the cost of transportation is equal to the losses incurred during transmission. If the optimal spot prices at the point of receipt and the point of delivery are known, the cost of congestion can be calculated as the difference between the spot prices, less any losses. Spot prices can be calculated using optimal power flow models.

This type of system is known as nodal pricing because the price of transmission depends on the origin and destination node. Each origin-destination node pairing has its own price. It has been suggested that setting up and using such a system of prices might be difficult, particularly in networks with many nodes (Walton and Tabors 1996). Zonal pricing has been suggested as a more manageable alternative. In zonal pricing, nodes with similar spot prices are grouped together for pricing purposes. Pricing is essentially the same as nodal pricing, substituting origin and destination zones for nodes.

A third approach to congestion pricing is to define physical rights to congested paths and then auction these rights. Such a scheme has been proposed by the Coalition for a Competitive

[6] There is much disagreement among the various proponents of megawatt-mile schemes as to the correct method of computing the relevant megawatt miles.

Electricity Market (CCEM) in response to the FERC Capacity Reservation Tariff Notice (CCEM 1996). Like the nodal and zonal pricing, this approach, if successful will produce the economically correct charges for congestion. Since all congestion pricing schemes will lead to the same economically defined congestion prices, we can talk about congestion pricing while ignoring the details of the particular pricing scheme used. Instead, we focus on the intended outcome.

Because congestion prices are based on marginal costs, network fixed costs cannot be recovered using congestion pricing alone.

2.1.4 Combined Rates

The variants of congestion pricing are the only pricing methods that efficiently allocate capacity in a constrained network, but they do not provide a means for transmission providers to cover their fixed costs. Postage stamp and MW-mile rates cover fixed costs, but fail to charge for congestion properly. In Section 5, we argue that no single charge covering all transmission costs (fixed and congestion) can be economically efficient. We must therefore consider combining different types of rates.

Most congestion pricing proposals pair nodal prices with a separate access charge (usually a postage stamp charge). The nodal prices ensure a competitive market and efficient allocation; the access charge allows the transmission provider to recoup the fixed cost of the network.

2.2 FERC's Order 888 and Point-to-Point Pricing

Restructuring is occurring within a regulatory environment that is also evolving. FERC is attempting to move restructuring forward (by mandating open access) without interfering with the evolution and innovation already occurring within the industry. The current federal regulatory environment is defined primarily by FERC's Order 888 (FERC 1996a). It is therefore important to understand what Order 888 does and does not say, and how FERC intended it to be used. This section provides an overview of the current regulatory environment. For more details on Order 888 and its potential impact on renewables, see Porter (1996) and Ellison, Brown, and Rader (1996).

2.2.1 *What Does FERC Require in 888?*

FERC's goal in issuing Order 888 was to remedy undue discrimination in access to transmission networks. Since transmission lines have historically been owned by utilities operating as regional monopolies, these utilities controlled whether and to whom electricity could be transported in interstate commerce. By forcing owners of transmission lines to offer transmission service to other utilities and non-utility generators on a nondiscriminatory basis, FERC opened markets to competition.

FERC Order 888 requires that public utilities file a single wholesale open access tariff offering two types of transmission service: point-to-point and network service. FERC defines point-to-point service as follows:

> Firm flexible point-to-point service in the Open Access Final Rule . . . defines rights and sets prices based on transmission capacity reservations. The transmission user designates points of delivery (PODs) and points of receipt (PORs) and makes a capacity reservation for each POD and for each POR. [FERC 1996b]

Although this definition encompasses contract-path agreements, it is not limited to that definition of transmission service. Where a contract-path agreement specifies a specific route over which power could travel, FERC's definition of point-to-point service specifies only the point of receipt and delivery. This definition is also consistent with postage stamp, megawatt-mile, and (arguably) congestion pricing.

Network integration transmission service is intended to allow transmission customers the same flexibility in integrating resources and loads that the owner of the transmission system enjoys. Under network service, the transmission customer specifies a set of resources and loads but can use the entire transmission network to provide service without paying for each resource-load pairing separately. The customer pays a share of the transmission provider's annual transmission revenue requirement proportional to his share of system peak load.

In an unconstrained system, this definition is unambiguous. Variation in the load of network customers can be accommodated without infringing on the reserved capacity of point-to-point customers. On a congested network, however, implementing network service is more complex. The most common interpretation of network service is service without further congestion payments. In a constrained system, this does not create appropriate incentives to network customers. In order for the transmission provider to assure that sufficient capacity is available to meet its native load and the loads of its network customers, it must have accurate forecasts of those loads. However, network customers have no incentive to provide accurate forecasts of their loads, since the utility is contractually obligated to meet their transmission needs for serving load, whatever their forecasts. Since how much capacity is available for reservation by point-to-point customers depends on how much capacity is reserved for network service, the lack of accurate forecasts could severely hamper the utility's planning efforts.

Order 888 attempts to create a secondary market for point-to-point transmission service by requiring that open access tariffs explicitly permit the reassignment of a holder's firm transmission capacity rights to any eligible customer. FERC gives three reasons for allowing the reassignment of transmission capacity:

(1) It helps holders of firm transmission capacity rights to manage the financial risks associated with their long-term transmission commitments.

(2) It reduces the market power of transmission providers by enabling customers to compete.

(3) It fosters the efficient allocation of transmission capacity.

Order 888 also creates a price cap on capacity reassignment. The price for reassigned capacity is capped at the highest of the rate paid by the assignor to the transmission provider, the transmission provider's maximum firm transmission rate in effect at the time of the transaction, or the assignor's opportunity cost. Because network service does not specify capacity rights, network transmission service is not reassignable.

In its CRT NOPR (FERC 1996b), FERC proposed replacing these two services with a single capacity reservation tariff. Under the proposal, all firm transmission service would be reserved, and all reserved service would be firm service. The capacity reservation tariff would be based on point-to-point service, with all nominations for capacity reservation evaluated using the same standard. Making all firm service reservation-based would make it much easier to calculate the available transmission capacity. This could lead to the expansion of the secondary market for transmission service, which would be beneficial to intermittent generators.

Non-utility generators (NUGs), including most intermittent renewables, are generally unable to use network service under the present system. Since they already use point-to-point service, their service would not change under the proposal and they could potentially benefit from an expanded secondary market. Utility-owned intermittent generators, however, would no longer be able to take advantage of network service. Under the capacity reservation system, they would find themselves on the same footing as NUGs.

Like Order 888, the NOPR fails to recognize the functional distinction between congestion charges and access charges. It reflects FERC's implicit bias toward capacity-based charges, which can be unfair to intermittent generators with low capacity factors.

2.2.2 Current Interpretations of FERC Order 888

Based on a sampling of transmission rates published on the Internet (in January 1997), most utilities have adopted the pro forma tariff from FERC's Order 888 virtually verbatim. Although FERC has stated that it did not intend to mandate a particular pricing scheme, transmission providers have been extremely conservative in their interpretations of Order 888. The firm transmission schedule from the pro forma tariff describes rates for yearly, monthly, weekly and daily capacity reservation in terms of $/kW for the reservation period. This is a postage stamp rate. It does not depend directly on distance (unless multiple zones are crossed), it provides no information about congestion, and the price paid depends only on the capacity reserved, not the actual energy transmitted. Nonfirm service is priced similarly for monthly, weekly and daily reservations. Hourly service is also available, priced on a per-MWh basis. Table 1 shows a sampling of the rates we collected. To make rate comparisons easier, we have expressed all rates in terms of $/kW-month.

Table 1. A Selection of Rates under Order 888

$/kW-Mo	ConEd	Penn-sylvania P&L*	PGE	BECo	Wisconsin P&L**	Public Service Co. of NM	Salt River Project	SoCal Edison	SDG&E	SMUD
Firm										
Long-term	3.54	1.05	1.00	1.80	NA	2.07	1.82	1.95	2.46	0.78
Monthly	3.63	1.05	1.00	1.80	1.00	2.07	1.82	1.95	2.46	0.78
Weekly	3.64	1.04	1.00	1.80	1.00	2.07	1.82	1.95	2.46	0.78
Daily	5.17	1.52	1.40	1.80	1.00	2.07	2.43	2.29	3.46	1.10
Non-Firm										
Monthly	3.64	1.05	1.00	1.80	0.60	2.07	1.82	1.95	2.46	0.78
Weekly	3.64	1.04	1.00	1.80	0.65	2.07	1.82	1.95	2.46	0.78
Daily	5.17	1.52	1.40	1.80	0.64	2.07	2.43	2.29	3.46	1.10
Hourly	7.67	2.28	2.12	1.83	0.66	2.07	3.83	3.43	5.18	1.64

* Pennsylvania Power & Light's rates are for their 500 and 230 kV lines.

**Wisconsin Power & Light's daily rates are for Monday through Friday and hourly rates are on-peak. These rates were collected in January 1997.

All power transmission must be scheduled.[7] Scheduling requirements vary between utilities. Some require one-day advance notice, whatever the term of the reservation. Others require earlier notice for longer term service—one week for weekly service, one day for daily service, one hour for hourly service. Most transmission providers will accommodate reservations made after the stated deadline, "if practicable."

[7] The amount of capacity scheduled may be less than the amount reserved. Although reservations allow for long-term planning and allocation of transmission capacity, scheduled transmission is what matters for short-term system operation.

For most of the utilities we surveyed, the rates for firm and nonfirm service were the same. However, prices did tend to increase as the reservation period decreased. Because hourly service is priced on a per-MWh basis, it is more difficult to compare to long-term rates. Typically, a generator that purchased long-term firm transmission and used 100% of its reserved capacity would have spent about twice as much if it had purchased hourly transmission. If that generator used only 50% of its reserved capacity, its average transmission cost per MWh would be much higher—comparable to the hourly nonfirm rate.

3 Special Transmission Issues for Renewables

There is a small but growing literature on the importance of transmission pricing for renewables. Porter (1996) and Ellison, Brown, and Rader (1996) discuss FERC Order 888, and both studies identify key technology and resource-related factors that make the cost of transmission service particularly high for renewable energy generators. Rosen and Bernow (1994) suggest a different type of transmission pricing structure (described in more detail later) that is less detrimental to renewables.

In this section we build on this existing literature. We first discuss the importance of firm fixed-price transmission contracts for financing renewables. We then describe the technology and resource-related issues that make transmission pricing particularly important for renewable energy generators and provide an example to illustrate the impacts of capacity factor/intermittence and distance on transmission costs. Finally, we draw some general conclusions about the benefits and detriments of certain rate structures to four types of renewable generation (biomass, geothermal, solar, and wind).

3.1 The Desirability of Firm, Fixed-Price Transmission Contracts

Most large-scale, non-hydroelectric renewable energy projects in the U.S. have been developed, owned, and financed by non-utility generators (NUGs). Electric output is sold to nearby utilities through long-term power purchase agreements, often contracts developed under the Public Utilities Regulatory Policies Act of 1978. Since the early 1980s, the NUG industry as a whole, and the renewable energy industry in particular, has relied extensively on stand-alone project financing. In these arrangements, lenders look primarily to the cash flow and assets of a specific project for repayment rather than to the assets or credit of the promoter of the facility. The debt contract is a fixed obligation and the debt investor does not profit, beyond a certain level, from project success. Therefore considerable certainty concerning future revenues and costs has historically been required by lenders in project financing, especially for technologies such as renewables that are frequently not as cost competitive as alternative generating sources.

As a component of the due diligence process, lenders will typically examine transmission access and costs to decide: (1) whether there is a high probability that the generator’s power can be transmitted to the purchasing party when needed; and (2) whether the cost of this transmission service affects the likelihood of a default on the loan. To reduce the risk of default, lenders will generally prefer firm, fixed-price transmission contracts over nonfirm, variable price service. A firm contract provides some certainty to the lender that transmission service will be provided and that it will be provided at a given price. Nonfirm service, on the other hand, might require the lender to assess the worst-case situation in which transmission service is either unavailable or available at a higher cost than expected.

Historically, most NUG power plants have been located within the service territory of the utility purchaser. Therefore, transmission contracts and transmission access were less of an issue for investors. In an era of open transmission access, however, it can be expected that more renewable power plants will require wheeling through one or more transmission systems. All else being equal, because of financing issues, renewables will prefer a firm, fixed price transmission contract. As described below, however, low capacity factor/intermittent resources (such as wind and solar) may have to pay a premium for firm transmission service if it is available only via capacity-based, take-or-pay contracts.

3.2 Capacity Factor and Intermittence

The capacity factor of a power plant is simply the amount of energy it produces divided by the amount it would produce if it operated at full capacity for the entire year. Capacity factors for individual generators differ substantially, as do the capacity factors of different types of generators (see Table 2). Base-load power plants (nuclear and coal, for example) have very high capacity factors, sometimes exceeding 90%. Peaking technologies (natural gas combustion turbines, for example) often have much lower capacity factors, sometimes below 10%. Of the renewable energy resources, biomass and geothermal often act as base-load facilities, with relatively high capacity factors. Wind, photovoltaic (PV), and solar thermal power plants typically have lower capacity factors because of resource constraints.

The low-capacity-factor renewable technologies (wind, PV, and solar thermal) are often also classified as intermittent because the output of these facilities fluctuates due to uncontrollable natural causes. This is quite unlike standard generation technologies whose output is controlled deliberately in response to price or cost fluctuations. This property of intermittence is a crucial handicap for renewables under the common type of capacity-based access charge (see Section 6). In fact, it is intermittence that causes a low capacity factor to be a serious liability in the procurement of firm transmission services.

Table 2. Typical Operating Characteristics of Renewables

Technology	Typical Capacity Factor	Intermittent?
Biomass	70%	No
Geothermal	85%	No
Solar (PV and Solar Thermal)	25%	Yes
Wind	30%	Yes

Take-or-pay contracts favor generators with high capacity factors and low variation in output (e.g., technologies that are not intermittent). Such generators can accurately forecast how much transmission capacity they will need and can fully use their reserved capacity most of the time. Low capacity factors and intermittence present a problem for generators under take-or-pay transmission contracts. A wind or solar generator that has purchased firm transmission service is forced to pay for unutilized capacity when the resource is unavailable and the plant has little or no electric output. Intermittence makes it difficult to match firm transmission contracts with estimated seasonal, daily, and/or hourly electrical production.

Wind and solar are expected to be the most detrimentally affected by the low capacity factor/intermittence problem. Any transmission pricing mechanism that charges on a capacity reservation, take-or-pay basis will affect these renewables negatively. (Geothermal and biomass facilities will not, generally, be detrimentally affected by capacity-based, take-or-pay transmission tariffs.)

3.3 Distance from Load

Because the siting of renewable power plants is based in large part on the availability and quality of the renewable resource (high wind speeds, high insolation rates, geothermal resources, or biomass fuel availability), many renewable generators are located farther from loads than are other types of electricity generators. In addition, wind and central station solar power plants are often land intensive. Even when resources are available near load centers, the cost of land may make such projects uneconomic. As a result, some renewable facilities transmit power over longer distances, and therefore through more zones (utility service territories, for example) than the average standard generator. Where a renewable generator must pass through two or more transmission zones, “pancaking” of transmission costs may occur.

Because most of the transmission pricing schemes currently under consideration are based in part on distance, renewables may face higher-than-average transmission costs and transmission-related costs may act as a barrier to renewables development. All of the renewable resources considered in this report could, on average, experience these distance-based costs as all are at least partially location dependent.

3.4 Location Flexibility

Not only are renewable resources often located far from load centers, but resource availability also reduces generators’ locational flexibility. Therefore, renewable generators may find it more difficult to choose locations away from constrained lines or other high-cost transmission areas than more traditional types of electric generators.

Location-dependence is perhaps of greatest concern for geothermal developers. Cost-effective geothermal resources are only available in a few locations. Wind and biomass facilities are also relatively location dependent. Solar technology, while subject to resource availability, may be less affected by this problem than the other technologies. Any transmission pricing mechanism that charges based on transmission constraints may be detrimental to renewable energy resources, especially those with little location flexibility.

3.5 Coincidence with System Peak

Coincidence refers to the covariance between the hourly electric output of a power facility and load. Technologies whose output follows system load have a high coincidence. Solar output, for example, often closely follows system load. The coincidence of wind power, on the other hand, depends substantially on the specifics of the resource.

Transmission congestion will not always occur during periods of peak load. However, on average, transmission lines are likely to be most congested during these periods. Under congestion-based transmission pricing methods, resources with a high coincidence with system peak are more likely to incur higher transmission costs than those resources that have a low coincidence with system peak. Solar technologies may therefore be particularly affected. In addition, transmission losses are often higher during the system peak. If transmission losses are charged directly, technologies with a higher coincidence may experience even greater costs.

3.6 Estimating the Cost of Transmission for Renewables

In this section, we provide an example to illustrate the impact of distance and capacity factor/intermittence on the cost of transmission for renewables. Terms used in this example are abbreviated as shown in Table 3.

Table 3. Abbreviations

Rate Variable	Symbol
Capacity factor	CF
Peak flow	F
Zones	Z
Zonal postage stamp rates	a, b, c
Average postage stamp rate	∀
Total transmission cost	TC

Our example assumes a postage stamp transmission pricing structure with capacity-based, take-or-pay firm contracts. This arrangement is typical of current practice. We ignore losses and assume that pancaking occurs when more than one zone is crossed. Although the example is for a postage stamp system, similar results would be obtained under any pricing approach that both: (1) charges based on peak capacity (take-or-pay); and (2) charges with distance more-or-less linearly.

In our example, if a particular transmission contract is executed across three zones, the formula for the transmission charge would simply be:

$$TC = a \times F + b \times F + c \times F \qquad \textbf{(1)}$$

where a, b, and c are the charge rates in each of the three zones.

If the zones have similar embedded costs per peak kW served, the three coefficients will be similar and the formula will simplify to:

$$TC = \alpha \times F \times Z \qquad \textbf{(2)}$$

where α is the average postage stamp charge rate.

The energy (in kWh) transmitted by a renewable generator is given by:

$$kWh = CF \times 8760 \times F \qquad \textbf{(3)}$$

Dividing the total transmission cost by the kWh transmitted gives the transmission cost in $/kWh:

$$TC/kWh = \frac{\alpha \times Z}{8760 \times CF} \qquad \textbf{(4)}$$

Using formula (4), Table 4 shows how capacity factor and distance transmitted affect the cost of transmitting energy. We assume a zonal postage stamp rate of $24/kW-year, which is a reasonable approximation of current practice. (Actual rates vary significantly between transmission providers; this value is in the same range as transmission tariffs being posted on the Internet by transmission providers as shown in Table 1.)

Table 4. Impact of Capacity Factor and Distance on Transmission Costs for Intermittent Resources

Capacity Factor	Zones Crossed		
	1	2	3
20%	1.37 ¢/kWh	2.74 ¢/kWh	4.11 ¢/kWh
40%	0.68 ¢/kWh	1.37 ¢/kWh	2.05 ¢/kWh
60%	0.46 ¢/kWh	0.91 ¢/kWh	1.37 ¢/kWh
80%	0.36 ¢/kWh	0.71 ¢/kWh	1.07 ¢/kWh
100%	0.27 ¢/kWh	0.55 ¢/kWh	0.82 ¢/kWh

Table 4 illustrates three important points. First, with pancaking rates, the contracted distance has a significant impact on transmission costs. Because the best locations for renewable generators are, on average, farther from loads than for other generation technologies, renewables are more likely than other generators to have to pay more than one postage stamp rate. Second, low capacity factor, intermittent technologies such as wind and solar have particularly high transmission costs on a per-kWh basis when capacity-based charges are applied. Biomass and geothermal technologies, on the other hand, may benefit from capacity-based transmission tariffs relative to their competitors because of their high capacity factors. Finally, the most basic of our conclusions is that the cost of transmission for renewables can be a significant component of total costs. For a low capacity factor renewable generator, costs of more than two cents per kWh are more than possible when multiple zones are crossed. Clearly, these costs are significant enough to act as a serious market barrier to renewable energy. In fact, given these high costs, designing "renewables-friendly" transmission pricing approaches should be considered a high priority for the renewable energy industries, especially wind and central-station solar.

3.7 Impacts of Different Transmission Pricing Methods

Certain transmission pricing structures tend to favor certain types of generation and to disfavor others systematically. Non-systematic effects, however, often play a dominant role in determining which structure would be most favorable for any specific renewables project. Therefore, a more detailed case-by-case assessment of specific transmission pricing proposals is necessary to determine the relative benefits and costs of these proposals. For example, given a basic understanding of the pricing approaches discussed in this study, some readers might guess that postage stamp rates would reduce the cost-per-mile of transmission service and that megawatt-mile pricing might increase these costs. However, this intuition is not entirely correct; postage stamp rates can vary widely depending on the area, and they do reflect transmission distances through pancaking across zones. Therefore, rather than determining which of the three broad transmission pricing methods discussed in Section 2.1 is "better" for renewables, we provide a qualitative discussion of the components of each proposed approach that might advantage or disadvantage these technologies.

3.7.1 *Postage Stamp*

On average, capacity-based postage stamp transmission rates most negatively affect those facilities that transmit short distances and have low capacity factors. Within an individual zone, postage stamp rates do not depend on distance. A power plant transmitting power to a load one kilometer away would pay the same access charge as one transmitting power 100 kilometers, as long as they stayed within the same zone. The price per kilometer is very high for short distance transmitters, but can be very low for generators serving a distant load in the same zone. By this logic, renewables may pay less per mile (on average) under postage stamp rates than other generating technologies since renewables are frequently located far from load.

For even longer distances, however, costs become roughly proportional to distance because of pancaking across multiple zones. Pancaking leads to a lumpy relation between cost and distance because even small changes in distance can increase costs dramatically if a zonal boundary is crossed. If zones are small, greater distance from load will mean renewables will be more likely to face pancaked charges than other generating technologies. Renewables will be most advantaged by postage stamp pricing where the zones are large and pancaking is less likely to occur.

As long as postage-stamp pricing is based on take-or-pay capacity reservations, low capacity factor/intermittent generators (wind and solar) will be penalized relative to standard generators. However, if the charges were based on energy rather than capacity, low capacity factor resources would benefit.

3.7.2 *Megawatt Mile*

As often proposed, megawatt-mile pricing would charge based on peak capacity. Therefore, low capacity factor/intermittent resources may be penalized in much the same way as in postage stamp pricing. Megawatt-mile pricing also explicitly charges based on the distance the transmitted power travels which, on average, may be approximated by the geographic distance between the generator and the load. Therefore, the farther the generator is from load, the higher the transmission charges on average. Although any real comparison between the two approaches is necessarily case specific, renewable generators may be more negatively affected by this pricing method than by postage stamp pricing because of distance effects.

3.7.3 Congestion Pricing (Nodal)

Congestion-based pricing proposals will, on average, negatively affect technologies that: (1) cannot locate around transmission constraints; (2) must transmit power over longer distances, therefore passing through more constrained areas; and (3) have output that is coincident with periods of congestion (often expected to be at the system peak). All of the renewable technologies considered in this report could be disadvantaged compared with other generating sources by this approach because renewables often do not have much location flexibility. Resources whose output is not coincident with the periods of congestion (some wind resources) may be advantaged by the pricing proposal compared with technologies whose output is coincident (solar, for example, often has output that matches daily load profiles). However, congestion pricing does not typically recover the full embedded cost of the transmission system. Thus, depending on how the excess costs are allocated across generators, this system may or may not affect renewables significantly.

4 Alternatives to Firm Take-or-Pay Transmission Contracts

As we have shown in Section 3, renewables developers have historically relied on take-or-pay, capacity-based transmission charges to reserve firm capacity. For low capacity factor, intermittent renewable generators (wind and solar), this form of transmission pricing can increase costs dramatically because the generator is forced to pay for unutilized capacity when the resource is unavailable. In this section, we describe and evaluate four alternatives to purchasing firm transmission under the current capacity-based, take-or-pay system: (1) purchasing nonfirm transmission service; (2) buying firm contracts that match generation patterns; (3) purchasing firm contracts and selling what is not used in a secondary transmission market; and (4) using a power marketer to firm the power. These options are not mutually exclusive; a renewable generator might be best served using a combination of these strategies. In addition, we consider a fifth option: changing the current capacity-based, take-or-pay transmission pricing system to one that charges based on usage.

4.1 Buy Nonfirm Transmission Service

To reduce transmission costs, a generator could purchase nonfirm transmission. Like firm transmission, nonfirm transmission is usually reserved. Nonfirm transmission, however, has two advantages over firm service. First, a firm transmission capacity reservation must be arranged far in advance. Actual use of the reserved capacity is then scheduled as the generator becomes able to forecast its output precisely—often on a daily basis. Nonfirm transmission is essentially just scheduled; no advance capacity reservation needs to be made. However, the generator must pay for the scheduled service whether it is used or not (making it a take-or-pay service).[8] Second, nonfirm transmission is typically available hourly. With a perfect hourly forecast of output, hourly nonfirm service is an energy-based charge. A capacity reservation is made for each hour, and the payment is made in \$/MWh. Unfortunately, many utilities require that hourly reservations be made a day in advance, and hourly nonfirm service will only approximate an energy charge to the extent a generator can make accurate forecasts that far in advance.

Purchasing nonfirm service exposes the developer to both availability and price risks. Most transmission providers require at least 12- to 24-hour notice to schedule nonfirm service. The

[8] A deeper understanding of capacity-based and energy based charges is gained by noting that capacity-based charges come in a continuum of varieties with an energy-based charge being the limit point at one end of the continuum. The purest form of a capacity-based charge is based on peak-use over an extremely long time horizon, say 10 years. As the time interval over which the peak is measured becomes shorter, it becomes increasingly possible for an intermittent generator to match purchased capacity to load. For a 10-minute peak-based charge, the matching could be nearly as good as the perfect matching achieved with an energy-based charge.

more predictable the generator's output, the easier it is to make such advance reservations. Purchasing nonfirm transmission might be a viable option for a solar generator that can make fairly accurate weather forecasts a day in advance. However, because the availability of wind can vary from hour to hour, wind generators would need to be able to make reservation with very little advance notice to use nonfirm service optimally. Although making reservations for the following hour is sometimes possible, such short term availability can be unreliable, particularly on lines where congestion is a problem.

To see how purchasing nonfirm transmission capacity can be more cost effective for an intermittent generator, consider a 10-MW solar plant that produces 2,000 MWh each month. Transmission rates are $1 per kW-month for monthly firm transmission and $2.90 per MWh for hourly nonfirm.[9] At these rates, 10 MW of firm capacity would cost $10,000 per month, while hourly nonfirm would cost only $5,800 per month.

As discussed in Section 3, financing restrictions may limit a generator's ability to use nonfirm transmission service. Under firm contracts, transmission expenditures are predictable. Because nonfirm prices can vary, because availability may be limited, and because nonfirm service is by definition less reliable than firm transmission, obtaining financing for a project without a firm agreement may be more difficult. However, even if a generator were unable to rely exclusively on nonfirm service, it might be able to use a combination of firm and nonfirm that would simultaneously reduce its costs and satisfy lenders.

4.2 Buy Firm Contracts that Match Generation Patterns

Intermittent generators might be able to purchase firm transmission based on the anticipated daily and seasonal availability of the resource. Again, resources with relatively predictable availability can use this method more effectively. Since firm transmission can be purchased on even a daily basis, generators whose output varies slowly and predictably can match their output fairly closely under current tariffs. Some biomass generators, for example, experience seasonal intermittence depending on the availability of the biomass fuel (e.g., agricultural wastes). Because the resource is available predictably and for long periods, a biomass generator could purchase firm transmission for the months that it is operational, with no penalty for having seasonal output. The output of wind and solar generators, in contrast, varies over a 24-hour period. One can imagine a firm contract for partial day service (e.g., 10 MW capacity daily from 8 a.m. to 6 p.m.). However, it is not clear whether the transmission provider would wish to agree to such service. Such a contract means 10 fewer megawatts that can be sold as firm capacity under a standard contract. Between 6 p.m. and

[9] These are actual rates taken from Portland General Electric's Pro Forma Open Access Transmission Tariff. Although rates vary greatly among transmission providers, this example is fairly typical of the relative prices of firm and nonfirm service.

8 a.m., the provider has 10 MW more available than during the day. This can be offered as hourly nonfirm or as another partial day service contract. Selling such capacity might be difficult, particularly if it is off-peak.

Even assuming such a partial day contract could be negotiated, it would not solve all the problems faced by intermittent generators. Again, predictability is key. Meteorology remains a field of uncertainty. Sunshine can only be predicted with accuracy a few days in advance. Wind is even more unpredictable, changing from hour to hour. Any partial day contract would have to be based on a forecast of resource availability, which suggests that wind generators would have to make very short-term purchases or risk reserving more capacity than they could use. Moreover, although firm transmission can generally be purchased on a daily basis, this can be more expensive than longer-term firm contracts. Daily firm service might work for solar generators, but even daily service might be too long a time horizon for wind generators because of the difficulty in predicting the resource in advance.

4.3 Buy Yearly Firm Power Contracts and Sell Back Unused Capacity

A wind or solar generator that has purchased firm transmission service under a capacity-based take-or-pay system will be forced to pay for unutilized capacity when the resource is unavailable. If a secondary market exists for transmission service, the generator could resell its transmission rights to recoup some of its costs. Selling transmission on the spot market entails both a price risk and the risk of being unable to find a buyer. This is particularly problematic for generators with daily variation in output. Solar generators would have capacity to sell during hours of darkness. During most of those hours demand is low, congestion is low, and the price of transmission on the secondary market would also be low. Overall, a poor time to try to sell capacity. Wind generators would have an even more difficult time selling capacity. They would have capacity available unpredictably, and often only for short periods. Although a lot depends on the resource profile, wind is often unpredictable over even short time horizons. The duration the capacity would be available would also be uncertain. Finding a buyer under these conditions could be difficult, even assuming a highly developed secondary market.

FERC's price cap on capacity reassignments may also make this option less attractive. The price cap is intended to prevent the assignor from charging unfair prices (higher than the greatest of the price paid to the transmission provider, the transmission provider's maximum rate, or the assignor's opportunity cost). Thus, the capacity holder is not allowed to earn undue profits through reassignment. However, he is not protected from taking undue losses if he is unable to find a buyer or if he is forced to sell capacity for much less than he paid.

If FERC's Capacity Reservation Tariff proposal goes through, it may help foster the development of a more vibrant secondary market. Because all firm capacity would be reserved under the proposal, it would be far easier for the transmission provider to calculate available transmission capacity and assess the impact of trades on power flows.

4.4 Use a Power Marketer to Firm the Power

Historically, most renewable generation has been built by private non-utility generators. These NUGs often do not have a diversified generation profile. In contrast, a utility or large power marketer may purchase renewable power as part of an extensive generation portfolio, consisting of a variety of facilities with differing output profiles. Even though wind and solar resources are unpredictable, the total generation profile for the utility or power marketer is quite stable and predictable. When the output of an intermittent generator tapers off, another resource can be ramped up. Even the presence of several intermittent generators, provided they do not all have the same generating profile, can reduce the total variability. As variability declines, firm transmission may be used more efficiently. A single intermittent generator, on the other hand, has highly variable output and must pay for that variability when purchasing transmission.

A wind or solar generator might be able to avoid the problems of intermittency by selling to a power marketer. The power marketer would then be responsible for purchasing transmission, possibly through network transmission service rather than point-to-point service, avoiding many of the difficulties discussed above. The power marketer's diversified portfolio might allow it to purchase transmission services more efficiently.

4.5 Pay-for-What-You-Use

The solutions described above assume that the current system of capacity-based, take-or-pay contracts continues. Several proponents of renewable energy have suggested alternative systems that would be inherently fairer for renewables. The underlying theme behind these proposals is that transmission payments should somehow reflect usage instead of being based exclusively on peak output. Rosen and Bernow (1994) suggest that transmission be priced on an "equivalent capacity" basis, where "equivalent capacity" is the average (not the peak) dependable capacity of a power source during the peak periods of a year. A 10-MW intermittent generator with a 20 percent capacity factor whose output was uncorrelated with system peak would have an average capacity of only 2 MW during peak periods. Depending on its capacity factor and degree of coincidence, a generator could pay as little as if the charge were energy based, or as much as if the charge were based on peak output.

Ellison et al. (1997) suggest that intermittent technologies should be permitted to pay for transmission service on a "pay-for-what-you-use" basis. These generators would reserve a maximum capacity usage right, but they would only pay for the portion actually used. This is essentially an energy-based charge. Because they would not have to pay for unused capacity, this would create an incentive for intermittent generators to reserve transmission capacity equal to their peak output, regardless of their actual forecasts of output. As noted by Ellison et al., a pure energy-based charge would not provide the appropriate incentives for handling congestion.

The American Wind Energy Association (AWEA) has made a similar proposal. AWEA suggests that wind generators be charged based on the load they impose on the transmission system, rather than a predefined contractual amount (Porter 1996). Such a system could also be described as "pay-for-what-you-use." FERC, however, was not receptive to the proposal.

In the next section we explore the contradiction between the need to manage congestion through take-or-pay firm capacity reservations, and the desire of intermittent generators to pay on a per-MWh or energy basis. We find that this contradiction can be largely resolved by splitting what is now a combination capacity reservation and access charge into its economically distinct components.

5 The Roots of the "Take-or-Pay" Dilemma

As described earlier, firm transmission service has historically been sold on a "take-or-pay" basis, meaning that the generator must reserve transmission in advance and pay for what is reserved no matter how much energy is eventually scheduled and transmitted. The use of capacity-based take-or-pay contracts is continuing undiminished under FERC Order 888. Take-or-pay contracts can be an effective method for managing risk; however, as they are currently used, they are inefficient and penalize low capacity factor, intermittent generators. The next two sections will argue that the take-or-pay system, in its present form, can cause the market to select an inefficient mix of generation technologies. But lest we throw out the baby with the bathwater, we must understand the logic of the present system before we can modify it to serve the needs of the generation market better.

5.1 The Two Necessary Types of Transmission Charge

The problem of charging for transmission has two completely independent components that are combined under current systems. The first component is congestion costs and the second is the fixed cost of grid construction and maintenance. Fixed costs are by far the larger of the two costs, accounting for 80 to 90+ percent of total costs.[10] Interestingly, these two costs are inversely related; if more is spent constructing the grid, the costs of congestion will generally be lower. By applying economic theory, we can see that the cost of *firm* transmission capacity is really only related to the cost of congestion. This will allow us to separate out the charges used to cover fixed costs and treat them in a more efficient and equitable manner.

Firm transmission service is needed for one and only one reason: to assure the purchaser that in case of congestion he will not be curtailed. Firm capacity reservation is thus essentially a form of insurance, so its cost should be equal to the expected cost of congestion. The firm capacity reservation charge buys guaranteed access to the amount of capacity reserved, whether the line is congested or not. It also serves to protect against fluctuations in the congestion charge.

---

[10] While this piece of folk wisdom is widely believed, we have as yet found no documentation of this "fact." It should be noted that FERC has accepted as true WEPEX's claim that when congestion charges are used to offset their embedded-cost access charge, the offset will never be complete, and thus there is no danger of "AND" pricing. The CCEM (1996) proposal makes the same assumption. The basis of this assumption is the theoretical understanding that in an optimally constructed transmission system, congestion charges would cover marginal costs but not fixed costs. Because fixed costs of transmission construction are considered large when compared with variable costs, congestion charges are assumed to be much less than embedded-cost access charges. In an overbuilt transmission system, congestion charges would be further reduced.

Since the nature of firm transmission is that it guarantees its owner the right to a certain number of MWs of capacity, firm capacity is necessarily measured in MW reserved and not in MW used. Therefore selling firm capacity by the MW-year reserved, as is now done, is natural and even necessary. As a form of insurance, firm service must also be take-or-pay. The firm reservation charge--the premium--is paid (or at least fixed) in advance. The actual congestion charges during the reservation period may be greater or less than the reservation charge. If they are greater, the customer has come out ahead. If they are lower, the transmission provider wins. Firm reservation charges should be set so that on average (over time and over the network's many firm customers) they equal congestion charges. The advantage of take-or-pay charges is that, unlike congestion charges, they are predictable. The customer knows exactly how much he will pay, and the transmission provider knows exactly how much he will receive.

Since the only reason for firm transmission service is insurance against congestion, the firm transmission charge should not be used to cover fixed costs. If it is known with certainty that a particular line will not be congested, the charge for a firm capacity reservation should be zero. This fact has been recognized in all of the more carefully designed transmission access schemes including IndeGO's TCR scheme (IndeGO 1997), Hogan's nodal pricing (Harvey et al. 1996), California's zonal pricing (Walton and Tabors 1996), Chao and Peck's transmission rights auction (Chao and Peck 1996), and the Coalition for a Competitive Electricity Market's proposal to FERC (CCEM 1996).[11]

Unfortunately, charging for congestion does not begin to cover the fixed costs of constructing power grids. Consequently, a separate access charge is needed. This fact has also been recognized in all of the transmission schemes just listed. What has not yet been agreed upon is the form of this access charge. In California, the probable outcome will be a capacity-based (MW-based) access charge simply because this is accepted practice.

5.2 The Advantage of Separating the Two Charges

Past and present practice fails to separate access charges from congestion charges. Since the charge for firm service must be based on reserved capacity, combining the two charges has meant that the access charge must be charged on the same basis. Once it is recognized that these charges should be and can be separated, the question of how to design the access charge naturally arises. This question has three important parts: (1) should it be based on MW or on MWh (i.e., on capacity or energy), (2) should loads or generators be charged, and (3) how should distance affect the charge. Here and in the next two sections we will address part (1).

[11] IndeGO is an association of utilities and power marketers in the Northwest that includes: Idaho Power Company, the Montana Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Power & Light Company, Sierra Pacific Power Company, and the Washington Water Power Company.

Appendix C gives a partial answer to (2). We have only begun looking at the complexities of (3), so the answer to the question of distance must wait for a future report.

To summarize our diagnosis of the current dilemma, we believe that fixed-cost charges are being wrongly collected based on reserved capacity because the charge for firmness (i.e., the congestion charge) has not been separated from the access charge. The next two sections show that the access charge should instead be a much simpler energy-based charge. If such a charge is implemented, only 10 to 20 percent of transmission revenues will be collected based on reserved capacity, while the remaining 80 to 90 percent will be collected based on actual energy transmitted. Switching to such a charge will have major benefits for low-capacity-factor intermittent generators, who will otherwise be penalized.

5.3 The Remaining Problem for Renewables

Although our proposal lessens the burden on low-capacity-factor intermittent generators, it does not eliminate the need for firm capacity-based transmission contracts. Although congestion charges are small compared to access charges, the intermittent generator who requires firm capacity years in advance will still be paying for capacity that it will not always be using when the line is congested. If this capacity cannot easily be sold on the secondary market at a fair market price, the intermittent generator will still have purchased more than was necessary. This problem can only be avoided if there is a liquid spot market in capacity into which the intermittent generator can resell unused transmission capacity.

5.4 The Role of a Competitive Market

There are many different proposals for structuring a competitive electricity market and it is not at all clear which, if any, will be chosen. Fortunately, all well-functioning competitive markets have some common features. For our purposes the two most important are: (1) that all such markets will produce the same congestion charges for congested transmission paths, and (2) no market will help in the determination of the access charge needed to cover fixed costs.

Under nodal spot pricing, congestion charges are determined by the difference in nodal spot prices and they are collected by the independent system operator. Under the CCEM and Chao and Peck proposals, congestion charges are determined by auctioning physical congestion rights. Under the California proposal, they are determined as the difference between market clearing prices in different zones. In this last case the prices will be slightly different from the “true” congestion costs because zones are a deliberate simplification and thus an approximation to nodal pricing. However, the system is designed to produce a very close approximation. Because any well-functioning competitive market produces congestion prices, we will take it as given throughout the rest of this report that appropriate congestion charges are in fact being charged. This will leave us with the problem of analyzing various possible mechanisms for access charges designed to recover fixed costs.

6 The Solution: An Energy-Based Access Charge

The analysis in this section assumes that a competitive market for transmission has already been created, through nodal pricing or an auction for physical transmission rights.[12] Since congestion charges cannot be used to recover the fixed costs of the transmission network, those costs must instead be recovered through a network access charge. The proper design of this access charge is addressed here.

Ellison et al. (1997) recommend that a special capacity reservation tariff be considered for intermittent technologies. Specifically, they suggest that such technologies pay for transmission based on energy transmitted ("pay-for-what-you-use") rather than peak capacity. In our analysis, we assume that congestion has already been handled by a separate firm reservation charge, creating competitive prices for scarce transmission resources. We then consider the effect of both energy-based and capacity-based access charges on intermittent technologies. Our analysis differs from the Ellison et al. proposal in two important respects: (1) we consider energy-based pricing for the access charge only (capacity-based take-or-pay may still be used for firm capacity reservation), and (2) we apply the energy-based charge to all generators, not just intermittent generators.

Three central concerns will determine our judgement of energy-based and capacity-based access charges. Do the charges affect the mix of generation technology? What is their effect on network congestion? Finally, how do the charges affect consumption patterns? Our findings are as follows:

1. Capacity-based charges needlessly penalize low-capacity-factor intermittent generators; energy-based charges do not.

2. In a competitive market, capacity charges can interfere with congestion prices, while energy-based charges do not.

3. Under the neutral assumption of uniform demand elasticity, an energy-based charge causes less distortion in consumption patterns than a capacity-based charge.

This section concerns only finding one; findings two and three will be covered in the following section. These findings will lead us to conclude that the access charge should be energy based.

---

[12] Since congestion pricing is inconsistent with network integration transmission service, our analysis implicitly assumes that all rates are point-to-point (i.e., FERC's Capacity Reservation Tariff Notice will be finalized).

The first of these findings is key. An access charge is essentially a tax, and if that tax is not equitable with respect to its effect on generation technologies, it will discourage some types more than others. This will result in an inefficient mix of generating technologies, which is wasteful from a social perspective, and in this case is particularly harmful for technologies with intermittent output and low capacity factors. To understand this point we will need a model of a competitive electricity market into which we can introduce the two types of access charges. We begin by developing that model and solving for the efficient technology mix. We go on to consider first the implications of an energy-based access charge and second the implications of a capacity-based access charge.

6.1 The Simplest Model

To evaluate an energy-based access charge, we must consider it in the context of a model electricity market. For our purposes that market must be competitive and must include intermittent, peak-load and base-load generators. The model also must specify a load-duration curve so that the least costly mix of technologies can be calculated, taking into account both the fixed costs of building the generation plants and the variable costs of operating them. This model will demonstrate that an energy-based charge does not distort the market's selection of technologies; i.e., that the least cost set of generators will be built and maintained by the market even after an energy-based access charge is implemented.[13]

The primary difficulty in constructing such a model is in modeling a competitive market. Such a market sets price equal to the marginal cost of the marginal generator. That means that peak-load plants are never paid more than their marginal costs (base-load plants are paid more when peak-load plants are in use) and so cannot cover their fixed costs. Thus, the most straightforward attempt at modeling competition in the electricity market runs into a serious market failure. In the real-world, this market failure might be overcome (sub-optimally) by several different mechanisms. Peak-load generators could have market power, allowing them to increase price above marginal cost. Imported energy could at times set the price above the marginal cost of peak-load generators. There could be "capacity payments" set by some regulatory authority. Because we do not believe that the details of how this market failure is overcome are crucial to the present analysis, we will adopt the simple assumption that peak-load generators have no fixed costs to cover. We justify this assumption with the following logic.

Peak-load, zero-fixed-cost (ZFC) capacity can be interpreted as the portion of standard capacity that is beyond the average-cost minimum. In other words, a base-load generator can only be thought of as truly base-load when it is operating efficiently. Consider a base-load

[13] If elasticity of demand were considered, we would find fewer generators being built because of the decrease in demand caused by higher prices, but the mix would still be optimal.

plant that operates at minimum average cost per MWh when operated at a capacity of 300 MW (its nominal capacity). However, it may be possible to squeeze another 20 MW out of this plant for short periods, but at a higher cost. If we consider the extra 20 MW of capacity as a separate plant, we can attribute the fixed cost of the base-load plant entirely to the first 300 MW of capacity. The last 20 MW of capacity then has no fixed costs.

In our simple model of a competitive energy market we assume that there is sufficient capacity with zero fixed cost (of the type described above) to cover the peak load. Although this is not true in real energy markets, we do not believe that more realistic assumptions would affect the qualitative aspect of our results. In future work we will show that this simplified way of removing the peak-load market failure will not substantially alter our conclusions.

We model three generation technologies. One of these provides ZFC capacity and another provides standard capacity at a fixed cost. The third is an intermittent renewable technology, which we assume has zero marginal cost but some fixed cost. For the purpose of our analysis the intermittent renewable can be thought of as either wind or solar. (In the real world the marginal cost of these technologies is not zero, but it is much lower than that of the standard technology because there are no fuel costs.)

We will measure capacity in MW, energy in MWh, and cost in $/MWh. While the cost of capacity is often annualized, for convenience we will convert it to a cost per megawatt-hour to make it comparable with the cost of energy. Given these conventions, we describe the three types of capacity as follows:

Table 5. Definition of Three Available Technologies

	Type			Cost in $/MWh	
Name	Number	Description	Capacity	Fixed	Variable
Zero Fixed Cost	0	Peak	K_0	$f_0 = 0$	$v_0 = 80$
Standard	1	Base	K_1	$f_1 = 10$	$v_1 = 40$
Intermittent Renewable	2	Intermittent	K_2	$f_2 = 10$	$v_2 = 0$

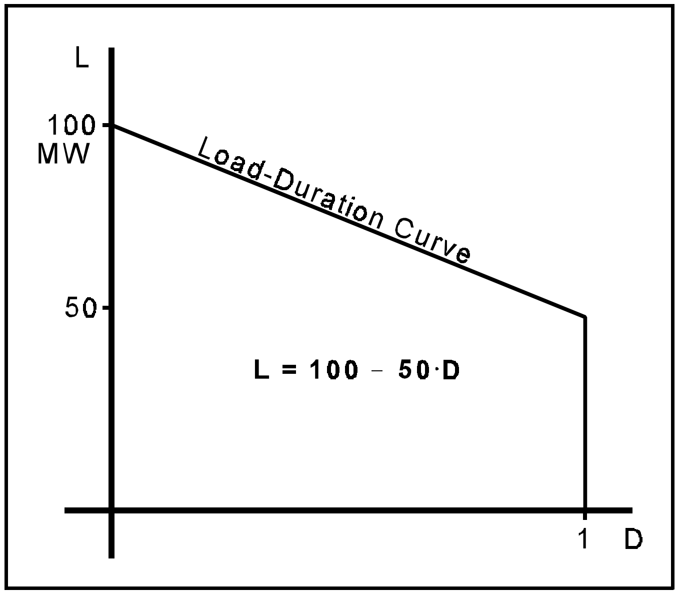
Our renewable technology needs further definition because it is intermittent and its quality, measured by its capacity factor, varies with location. The best sites, those where plants will have the highest capacity factor, will be selected first. Therefore we describe the capacity factor of the renewable technology as a function of total capacity built by the market. Because it is the capacity factor of the marginal plant that determines that amount of renewable capacity to be built, we define a marginal capacity factor function:

$$\text{Capacity factor of the marginal intermittent plant} = F(K_2) = 0.3 - 0.01\,K_2 \quad \textbf{(5)}$$

This function indicates that the first kW of intermittent capacity has a capacity factor of 30%, but when capacity reaches 30 MW, the capacity factor of the last kW installed will be zero.[14]

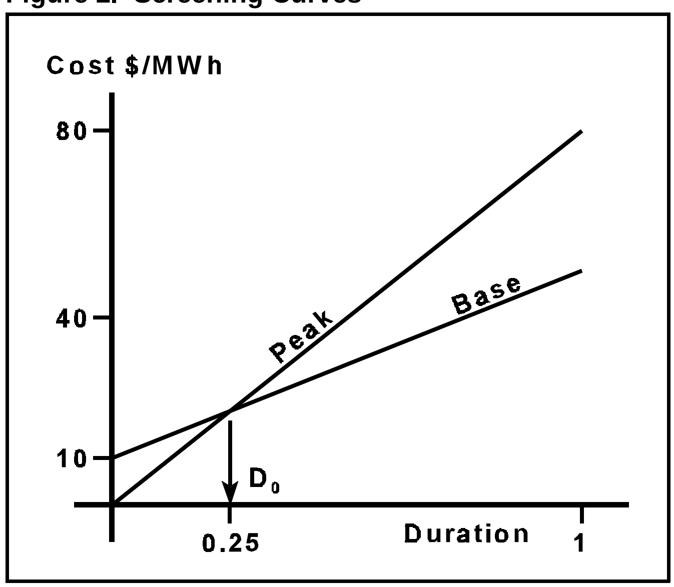
To solve for the least-cost technology mix we must also define a load-duration curve. We choose the simple curve shown in **Figure 1** which, though not realistic, will not interfere with the present analysis.

Figure 1. Load Duration Curve



We now have a sufficient specification to solve for the least-cost choice of generation technology. We begin by ignoring the intermittent technology and drawing the screening curves for the peak and base technologies. These are shown in **Figure 2**. These curves plot cost in $/MWh as a function of duration. Obviously, the lower cost technology should be chosen at each duration. The screening diagram shows us that the ZFC technology should be chosen for all loads of duration less then D_0, while standard technology should be chosen for all loads with greater duration.

Figure 2. Screening Curves



[14] This is obviously unrealistic, since the capacity factor would never go to zero but would instead taper off gradually. But this assumption is simple and harmless, as can be verified by replacing equation **(5)** with an arbitrary monotonically decreasing function.

6.1.1 What Technology Mix Would a Competitive Market Choose?

We have now employed the standard screening-curve technique to solve for the least-cost mix of ZFC and standard technologies and found that peak-load generators should be used to cover all load with a load factor of 25% or less. Would a competitive market produce this result? In our simplified model the key question is whether a competitive market will induce an efficient (least-cost) level of base-load technology. With zero fixed cost, whatever peaking technology is needed will surely be provided by the market, and if too much is provided there is no loss. This makes the market's problem of finding the right technology mix unusually simple, but the base-load problem is sufficient to represent the typical problem that the market faces in selecting the technology mix.

During the 75% of the time when peak-load technology is not needed to meet peak load, the base-load technology will be setting the market price for energy. In a competitive market, this means the price will equal the marginal cost of the base-load technology, or $40/MWh. At that price, base-load plants cannot cover their fixed costs. Fortunately, during the other 25% of the time, the price is set by peak-load technology at its marginal cost of $80/hr, so base-load plants can use this to cover fixed costs.

New base-load plants will be built in a competitive market as long as positive economic profits[15] can be earned but will not be built if profit is expected to be negative. If they are not being built, then natural attrition due to aging will slowly reduces their number. Ultimately a zero-profit equilibrium will be reached. That is, the market will naturally gravitate toward an equilibrium in which base-load plants make zero economic profits. Since increasing the number of plants reduces the duration during which peak-load plants set the price, we can write the zero-profit condition in terms of duration. By determining the peak-load duration that causes zero profits for base load plants, we also determine the base-load capacity. That zero-profit condition is as follows:

$$
\begin{aligned}
B &= D_0 \cdot (v_0 - v_1) - f_1 = 0 \\
D_0 &= \frac{f_1}{v_0 - v_1} = \frac{10}{40} = 25\%
\end{aligned}
\qquad \textbf{(6)}
$$

Note that this is the same equation that determines the intersection of the two screening curves. Therefore a competitive market selects the least-cost mix of technology just as is done by the screening curve analysis. This result holds for any number of standard technologies, with any combination of fixed and variable costs, as long as there is sufficient output from

---

[15] Economic profit is defined as profit above the minimum profit required to keep firms in the industry. At zero economic profit, firms already in the industry earn enough to stay in business, but profit is not high enough to attract new firms. Whenever we refer to profits in this report, we mean economic profits.

ZFC technology to cover peak load. Again, if sufficient ZFC technology is not available, then a market failure for peak load generation will need to be addressed through some type of market intervention. This is an advanced problem that will not be taken up in this report. Here we will simply put forth the two conjectures.

C1. Even with a peak-load market failure, our results concerning the two types of access charge would remain substantially the same.

C2. This market failure can be dealt with efficiently, and if it is, our results will be unchanged.

6.1.2 Adding Wind or Solar to the Technology Mix

It is now time to tackle intermittent renewable generation. Because the efficient level of intermittent capacity is below the minimum system load of 50 MW, the full output of intermittent generators can always be used. Intermittent generation should be added until the marginal unit is no longer profitable. This makes it easy to compute the efficient amount of intermittent generation if we know the durations of use of the other technologies. We have already calculated those durations, but that calculation did not consider the existence of the intermittent technology. For now we will just assume that the intermittent technology does not affect these durations and go on. In the next subsection we will examine the impact of intermittent generation on the duration of use of other technologies.

We begin the analysis of the intermittent technology by writing down its profit equation. Note that this equation, in keeping with the above discussion, makes use of the duration of the peak technology and the duration for which the base-load technology finds itself on the margin.

$$\text{Profit per MW of Capacity} = F(K_2)\cdot(0.25v_0 + 0.75v_1) - f_2 = 0 \qquad \textbf{(7)}$$

This can be solved for marginal capacity factor, $F(K_2)$, which can in turn be solved for K_2.

$$F(K_2) = \frac{f_2}{0.25v_0 + 0.75v_1} = \frac{10}{0.25(80) + 0.75(40)} = 20\% \qquad \textbf{(8)}$$

From Equation **(5)** we have

$$F(K_2) = 20\% = 0.03 - 0.01K_2 \quad \Rightarrow \quad K_2 = 10\,MW \qquad \textbf{(9)}$$

Given this efficient mix of peak- and base-load technologies in this example, the optimal capacity for the intermittent generation technology is 10 MW.

6.1.3 The Impact of Wind and Solar on the Use of Standard Technologies

As promised, we now consider the impact of intermittent generation on the standard technologies, and in particular on how the presence of intermittent generators changes their durations of operation. The answer is quite simple: if the intermittent technology is never the marginal technology, its existence and operation do not affect the durations for which the standard technologies are marginal. Because of this, our calculation of the efficient level of intermittent capacity needs no correction.

We arrive at this conclusion by noting that intermittent generation can be considered simply as a modification of the load-duration curve. The shape of the load-duration curve does not influence the duration at which it is efficient to switch from one technology to the next under the screening-curve analysis or under the market analysis. Therefore, intermittent generation does not affect these durations. This result is explained more fully in Appendix A.

6.2 Adding an Access Charge

We have now determined the least-cost mix of technologies for supplying the given load and wish to consider the consequences of imposing either of our two kinds of access charge. Because an access charge is like a tax, firms will try to avoid it, even if it means modifying their investments and levels of production. Because of this, taxes often cause inefficiencies. In our case these “taxes” could cause the market to adopt an inefficient mix of generation technologies. Specifically, the capacity-based access charge will be found to reduce the profitability of intermittent renewables generators and thus cause the market to adopt too little of this type of generation. We will now examine two possible forms of access charge to learn how they affect the technology mix.

It should be noted that a tax does not change the least-cost technology mix. No resource costs have been changed; it takes the same inputs to produce a MWh of energy using base-load technology with or without a tax. This means that any shift in technology mix caused by the tax will necessarily move away from the optimum, reducing efficiency and increasing resource costs.

6.2.1 The Energy-Based Access Charge

The analogy between a tax and an access charge is not only accurate but also helpful because it allows us to bring to bear the well-developed perspective of taxation theory. The central question is who bears the burden of a tax. Sometimes when a firm is taxed, that firm not only pays the tax, but also bears the full burden of the tax. This means that its profits are reduced by the amount of the tax. Other times the firm can pass the tax on to its customers as a price increase. Here, the customers bear the burden of the tax and the firm's profit is not reduced. Quite often the burden is shared between the firm and its customers. The question of who bears the burden of the access charge is central to our analysis and so we will often speak of it as a tax.

When we apply this tax perspective to an energy-based charge, we find that while generators pay the access charge, they do not bear its burden. This result holds for all types of generators, peak-load, base-load and intermittent, because an energy-based charge can be completely passed through by generators to the end users of power. From the generator's point of view, an energy charge simply increases the marginal cost of producing a kWh. Since there is absolutely no point in selling energy at less than marginal cost, and since in a perfectly competitive market it cannot be sold for more, this charge will be completely passed through to customers. Since this increases the energy price asked by every generator, no technology will be favored over any other. Consumers cannot avoid the price increase by switching generation technologies, so they will be forced to pay a higher price and thus to pay the energy-based access charge indirectly. The charge does not affect consumers' choice of suppliers, so the mix of generation technologies is unaffected.[16]

It is also useful to examine our profit equations to see how the profit level of each technology is affected by an energy-based access charge. To do this, we first note that all marginal costs are increased by the access charge of \$C/MWh. Thus, the three marginal costs become $v_0 + C$, $v_1 + C$, and $v_2 + C$. The case of the peak-load technology is simplest. Whenever peak load is operating, it sets price competitively at exactly its marginal cost, so its economic profit level is always zero. Base load is more subtle because its profit depends on the price set by the peaking technology and the duration of this price. Still, as can be seen in equation **(6)**, the profit of a base-load generator is affected only by a difference of two marginal costs, and this difference is unaffected by the access charge *C*.

Finally we examine how an energy-based access charge will affect the profit of an intermittent generator. The intermittent-generator profit equation **(7)** appears to be sensitive to the value of C, but this is an illusion. Equation **(7)** was simplified by setting the marginal cost of the

[16] Unless demand is completely inelastic, the higher price will reduce the quantity of electricity demanded. This may put some generators (of all types) out of business, but it will not affect the market's least-cost technology mix.

intermittent generator equal to its assumed value of zero. If we rewrite the equation to explicitly include the marginal cost of intermittent generation we obtain:

$$B = F(K_2) \cdot \left(0.25\,(v_0 - v_2) + 0.75\,(v_1 - v_2)\right) - f_2 \tag{10}$$

Clearly the access charge, C, will also cancel out of this equation and the profit of intermittent generators will be left undisturbed. Consequently, the access charge will not affect the market's selection of the technology mix. Intermittent generators will simply be unaffected by an energy-based access charge except possibly for a slight effect that operates on the entire market through demand elasticity. This is exactly what we want from an access charge.

Energy Result 1:

An energy based access charge does not affect the market's selection of the least cost technology mix.

This invariance of technology selection under an energy-based tax can also be seen with the screening curve analysis, which mimics the competitive market. The tax increases the slope of all screening curves by the same amount, raising all the intersection points vertically and leaving their duration values unchanged.

6.2.2 The Capacity-Based Access Charge

The alternative to an energy-based charge is one based on the maximum power output of a generating plant. This has historically been the approach used in the U.S. to price transmission service. Although the time period over which this maximum is computed obviously matters, we will simplify the analysis by taking it to be one year and assuming that all years are the same. Therefore, the peak output will simply be the plant's all-time peak output. Clearly, even in a market distorted by taxes, firms will not choose to build plants of greater capacity than will ever be used. Thus, we can simply view this access charge as a tax on plant capacity.

As with the energy-based charge, our first task is to determine the burden of the capacity-based charge when it is considered as a tax. This task immediately presents us with a puzzle. In a perfectly competitive market, producers cannot set the price higher than marginal cost. A capacity-based charge increases total costs but does not affect marginal cost because the capacity charge does not depend on actual output. This means the charge cannot be passed on and must be borne by the generators. If the market was perfectly competitive before the charge, as we assumed, generators were making zero economic profits. With the additional cost of the capacity-based access charge, the generators all become unprofitable. This cannot be a long-run equilibrium. We summarize this result as follows.

Capacity Result 1:

The initial effect of a newly imposed capacity-based access charge on a competitive market is to make all generators unprofitable.

Since this cannot be an equilibrium outcome, we must continue to trace the effects of a capacity-based charge. Although economic profits are negative, this will generally only be due to the fact that fixed costs are not being covered and should not be taken as an indication that revenue will fall below variable costs. Consequently, we should not necessarily expect any generator to immediately be put out of business. However, since fixed costs are not being covered we would not expect entry into the market. Consequently, as generating plants retire they will not be replaced. Over time, this will cause a reduction in generation capacity through attrition of older and more expensive plants. If the resulting generation capacity is insufficient to cover system peak, price will be driven above marginal cost. The increase in profit due to reduced capacity will allow generators to cover their access charge. Such profits resulting from reduced capacity are called scarcity rents.

Profitability could be restored in another way. A reduction in the number of firms could lead to market power. If firms leave the market by selling their capacity rather than retiring it, the resulting consolidation could provide the market power necessary to restore profits without reducing capacity. We now summarize our second result.

Capacity Result 2:

The initial reduction in profitability will lead either to increased market power or to scarcity rents, or to some of each. This will increase prices and restore the profits of those firms that remain.

This ambiguity in the market's response to a capacity tax makes it difficult to pin down the outcome precisely. Nonetheless, we will be able to prove a crucial result characterizing the outcome: Price will increase only on peak loads. In this report, we will prove this only within the context of our stylized example, but we believe the result is very general.

To prove this result within the framework of our example, we assume that the peak-load technology achieves a price increase that covers the cost of the capacity tax and brings its profit level back to zero, either through an increase in scarcity rent or market power. In other words, we assume that when peak capacity becomes scarce enough, or acquires enough market power, it will become profitable. This assumption does not imply that the pre-charge peak capacity becomes profitable (earns at least zero economic profit) but only that the remaining capacity in the new post-charge equilibrium will be profitable.[17]

[17] As the peak capacity is reduced toward zero, its cost advantage (in terms of $/kWh) over base-load technology grows without limit. (If there is only enough peak capacity to cover the 10 most peak hours, then what is saved during those 10 hours is the difference between constructing base and peak technology to cover those 10 hours; when this cost is distributed over the kWhs produced, the price is high indeed.)

The proof, which is given in Appendix B, proceeds by examining the price increase that is necessary for the peak technology to cover its capacity-based access charge. This price increase occurs only when the peak technology is in use. What is shown is that this price increase is sufficient to allow the base-load technology to cover its access charge also. If base-load generators could raise prices during nonpeak hours, they would more-than-cover the cost of the access charge and thus earn a positive economic profit. If this were true, it would draw more base-load generators into the market and depress the price for base-load energy. Thus, we would not be in long-run equilibrium. In equilibrium, base-load plants must make zero economic profit so they must at most cover their access charge, and as we just argued, this is done without their raising base-load prices. We now summarize our third result.

Capacity Result 3:

> A capacity tax falls on peak-load electricity users and does not increase prices during the base-load hours.

This tells us about the burden of a capacity-based charge on non-intermittent technologies, but we are most interested in the intermittent technologies.

6.2.3 Implications of a Capacity Tax for Wind and Solar

We have examined the implications of a capacity-based access charge for standard technologies. We now turn to intermittent technologies such as wind and solar. In this analysis, our primary tool will be Capacity Result 3 from the last section.

As we have noted, the market response to a capacity-based charge is ambiguous. The market may recover these charges either through market power or through scarcity rents. When the charges are recovered through scarcity rents, peak generating capacity is reduced, which implies that peak-load capacity will handle only load-durations somewhat less than the 25%. When the access charge is recovered through market power, the total capacity of peak generators is not reduced (there is no increase in scarcity). Consequently, such generators will supply all loads of duration 25% or less, just as they would in a competitive market.

For simplicity, we will only analyze the case in which profitability is restored purely through scarcity rents. Also for simplicity we will assume that the load duration curve and the cutoff

Therefore, as peak capacity is reduced towards zero and both its scarcity and market power increase, it will be able to charge very high prices for its service. Thus, it must be possible for peak capacity to cover its access charge for some low-enough level of capacity.

duration for the peak technology do not change. In reality the duration of peak cutoff could be reduced but this would only accentuate our result.[18]

We now have a situation in which peak-load generators (ZFC technology) mark up prices above their variable cost by some amount we will call $\bar{m}$ (which is measured in \$/MWh). During the 25% duration when peak-load generators run, they set the price according to this markup, and both base-load and intermittent generators operating during this period are paid this high price. We have already shown (Capacity Result 3) that base-load generators profit enough from this markup to cover their access charge. We now examine whether intermittent generators can cover the access charge.

Up to this point in our analysis, it has made no difference whether the intermittent generator's output was correlated with peak load. Now, however, generators whose output is higher during peak load hours (such as solar) will be better off than those whose output is uncorrelated with peak load (some wind generators). They will earn the peak-load markup on a larger share of their output. For now we will assume that our intermittent technology has an output that is uncorrelated with system load. Once we obtain our basic result, we will discuss the implications for generators with a higher degree of coincidence.

Of course, intermittent generators differ by capacity factor. Those with the highest capacity factors are most profitable and those with the lowest make an economic profit of zero. We analyze the marginal intermittent generator since they are at the most risk. Since we are assuming that our intermittent technology has an output that in uncorrelated with system load, the capacity factor during peak hours is the same as its overall capacity factor. For the marginal intermittent generator, we computed its capacity factor as 20% in equation **(8)**. This means that for each MW of capacity, a marginal intermittent generator will earn only an average of 20% of $\bar{m}$ for 25% of the year. From this we subtract the access charge A, which is measured in \$/MW of capacity (again assuming peak output equals capacity). This allows us to write the profit condition for intermittent generation as follows (assuming that these generators earn zero economic profit in the base case).

[18] The market power assumption is more complex but leads to an even stronger case of an energy-based charge. It will be addressed in future work. If peak-load generators set their markup to exactly cover their access charge, base-load generators will earn economic profit. This is because base-load generators produce at maximum output whenever peak-load generators are operating, whether the peakers are operating at 10 percent or 100 percent of their capacity. When there is free entry among base-load generators, this is not an equilibrium outcome, because economic profits will entice new base-load generators to enter the market. If there are barriers to entry, peak generators may be able to sustain market power with both base-load and intermittent generators benefitting from the markup. The effect on intermittent generators depends on how their output profile during periods of markup compares to that of peak-load generators. This depends on both the shape of the load duration curve and the intermittent technology's degree of coincidence.

$$\text{Profit per MW of Capacity} = 0.20 \times 0.25\,\bar{m} - A \qquad \textbf{(11)}$$

All we need now is the comparison between $\bar{m}$ and A, which is available in Appendix B. There it is shown in equation **(17)** that the average markup $\bar{m}$ equals A divided by the duration of peak load (25%). In other words, during the time that peak-load generators are running they must earn four times the access charge to make up for the fact that they only run 1/4 of the time. Substituting this value of $\bar{m}$ into equation **(7)** gives:

$$\text{Profit per MW of Capacity} = 0.20 \times 0.25\,A / 0.25 - A = -0.8A \qquad \textbf{(12)}$$

This shows that 80% of a capacity charge is borne directly by the marginal intermittent generator and not passed on to the customer. The intermittent generator that was the marginal intermittent generator before the capacity tax will no longer be profitable because it will be unable to cover its fixed costs. If the optimal number of intermittent generators has already been built, these will not be put out of business (since they can still cover their variable cost) and there will be no immediate social loss. There will only be a transfer of wealth from intermittent generators to customers.[19] If the marginal generator has not been built at the time a capacity-based access charge is imposed, it will not be built. In the long-run, intermittent generation will be reduced below the level that provides least-cost generation, resulting in an increased cost of power.

Capacity Result 4:

A capacity tax reduces the amount of intermittent capacity compared to the least-cost technology mix.

What happens if output is correlated with peak load? Looking at equation **(12)**, we see that the only capacity factor we could substitute into that equation that does not result in negative profit is 100%. The best any generator can do is earn zero profit, and that can only be accomplished by operating at 100% capacity factor during peak load hours. Even solar generators, which have a high degree of coincidence, fall short of a 100% capacity factor during peak. Although they would not suffer as much as a generator whose output was uncorrelated (or worse, negatively correlated) with peak load, these generators would be unable to earn a positive profit under a capacity-based charge.

[19] This statement relies on a comparison with the energy-based access charge which is both more efficient and more equitable.

7 Other Benefits of the Solution

In the last section we explored the impact of two types of access charges on the market's selection of generation technologies. In this section we look at the impacts of these same types of access charges on network congestion and on consumption. The effect on congestion is of first importance because this addresses the standard rationale for adopting capacity-based charges.

7.1 How Access Charges Affect Congestion

The standard "intuition" behind a capacity-based transmission access charge goes something like this: "A network must be built to accommodate its peak load, and all off-peak usage is essentially free. Therefore, it is the peak load that should have to pay for building the grid." While this attitude seems sensible, it fails to take into account two facts: (1) the maximum use of the network does not necessarily correspond to the system peak load, and (2) a competitive market automatically charges the appropriate price for use of the network at its capacity limit.

7.1.1 System Peak vs. Network Peak

One expects network congestion during periods of system peak load. After all, more power must be delivered from generators to loads. However, the problem of congestion is not limited to periods of peak demand. For example, PG&E reports that they have just as much trouble with congestion off peak as on peak (Benevides 1995).

Network use is determined not only by how much power is being generated and used but also by where that power is being generated and used. The transmission network connects areas with low cost generation and low loads to areas with higher cost generation and larger loads. It also allows trades between areas with different load patterns. An area at peak load can purchase power from another area rather than bring its highest cost generators on line. This is possible when other regions have power to sell—generally areas that are *not* at peak load. The system can become just as congested when there is variation between loads at different network nodes as when all the nodes are at peak load.[20]

[20] Consider the following example: Two cities, A and B are connected by a 1-MW line. There is an 8-MW generator at A and another at B. The cost of generation is $40/MWh at A and $60/MWh at B. Base load is 3 MW at A and 5 MW at B, and peak load is 8 MW in each city. Since A can produce power more cheaply than B, B prefers to purchase power from A if possible. At the system's peak load there is no flow on the network because the generator at A can only supply enough to meet the demand at A with no surplus to sell to B. Both A and B produce 8 MW to meet local demand, and no power is transmitted. At base load, however, the line is congested. After meeting local demand, the generator at A still has 5 MW of capacity available. It can sell power to B up to the limit of the transmission line. A and B both produce

Because we have seen that a capacity-based congestion charge causes a price increase only on peak (Capacity Result 3), such a charge does nothing to discourage the congestion of the grid when the system is not at peak load. In fact, it can discourage the use of electricity when the grid is not fully utilized.

7.1.2 *Competition and Congestion*

Capacity-based charges have been defended on the grounds that they manage congestion by properly charging for peak use. Here, we examine whether a capacity-based access charge can help manage congestion when there is already congestion pricing. Does an access charge provide some useful incentives for the use of the grid? If the capacity-based charge is to play a useful role in a competitive market, it must improve on the incentives already provided by normal congestion charges.

As noted earlier, several forms of competitive power markets have been proposed: nodal spot markets, markets for physical transmission rights, and multilateral trading markets. In each case, the backers of these proposals take great pains to argue that their proposed market structure would produce the "right price signals." In all cases, if the market works as intended and is not impeded by transaction costs and market power, the proposed market structure will produce these optimal prices. Fortunately, there is a core of agreement among these models and between their proponents. All parties agree that there is a set of optimal prices and agree on what those prices are.[21]

Optimal prices for energy differ by location, and they differ in a way that prevents trading parties from making voluntary choices that would overload the transmission system. In other words, the price difference between nodes A and B should be just great enough to prevent traders from overloading the path from A to B. Efficient dispatch of the system should take into account only the costs of using the system, not the costs of building it. Unfortunately, such an optimal pricing policy, while achieving least-cost operation, does not provide sufficient revenue to cover the cost of building the transmission grid. Perhaps this fact allows some room for a capacity-based access charge to improve on grid-use incentives.

Suppose an access charge were used to increase the cost of using a congested line beyond the cost that is already imposed by the standard congestion charge. This would reduce the use of

4 MW, with 1 MW being transmitted from A to B. Therefore, the line is congested at base load but not at peak load.

[21] This ignores the problem of unit commitment. This problem may require the use of more than one price, and may introduce non-convexities that prevent an optimal market solution. But this complication is not relevant for our comparison of the two types of access charges.

that line. Since the meaning of congestion is simply that the line is at its security limit, this reduction in use will bring the line below its security limit. That means line capacity will be left unused, and why would anyone build capacity that will never be used? It does not make sense to build a line and then impose a charge guaranteeing that some capacity will never be used. Therefore it does not make sense to go beyond the standard congestion charge.[22]

7.2 How Access Charges Affect Consumption

Fixed costs cannot generally be collected through marginal cost pricing. The problem of how to collect the additional revenue is an old one, and the solution for the demand side of the market is well known. Ramsey pricing causes the least loss of welfare. In fact, Ramsey prices are *defined* to be those prices that cause the least loss of welfare to consumers. Ramsey prices have the property that the markup above marginal-cost is inversely proportional to demand elasticity. Thus, the most revenue is collected from the consumers with the least elastic demand, i.e., those whose consumption pattern is changed least by the increase in price. In our case, we have found that a capacity-based charge raises the price only of peak users, while an energy-based charge raises the price of all users equally. If we knew that peak users had very inelastic demand compared with the elasticity of base users, then we would conclude that a capacity-based charge would cause the least distortion to consumption patterns.

---

[22] To reinforce this point we consider a one line example: Assume a generator at A and loads at A and B. Assume that at peak demand the line is congested and the price at B rises to $50/MW, while at A competition keeps the price down to $40/MWh. The implicit congestion charge will be $10/MWh. Let us assume this congestion charge is collected by the transmission provider either through a nodal spot price market or through a market in which it sells firm transmission rights, or collects a capacity reservation tariff in some other manner.

Now assume that the transmission provider, needing to cover the fixed costs of the transmission line, decides to levy an additional charge of $(2×8,760)/MW-year on the output of all generators. In order to stay in business, the generators (all of which are at A) eventually find a way to raise prices and return to a normal level of profitability (through scarcity rents or market power). For the sake of argument, say the new price at A is $45/MWh during peak hours.

Since the demand at B has not changed, and the supply is still limited by the congested line, the price at B remains unchanged. When the price at A increases by $5, the congestion charge decreases by $5 (remember it is the difference between the spot prices at A and B). Power from A still sells at $50 at B. Consumers at A pay $5/MWh more than they did before, consumers at B pay the same amount as before. Since consumers at A were not the ones causing congestion on the line, this hardly seems fair. Since consumers at B do not change their consumption (since the price is the same), so congestion is unaffected. The transmission provider collects its capacity tax, but collects half as much in congestion charges.

Imposing a capacity-based access charge on a system with congestion during peak load insures only that those causing the congestion escape the access charge. Trying to go beyond the normal and optimal congestion charge with an additional access charge is pointless.

In fact, there is little evidence on the relative elasticity of demand at various points on the load curve. The studies done have produced conflicting results (see Bohi 1981). We do know, however, that load shifting from peak to off peak is an additional source of peak-load elasticity beyond the simple reduction in demand. If the main source of elasticity were load shifting, it might be sufficient to prove that an access charge should be spread evenly over the load curve. Lacking hard evidence, we believe that no weight should be given to an argument to place the entire price increase on peak-load users. Under the neutral assumption of uniform demand elasticity, an energy-based charge causes less distortion in consumption patterns than a capacity-based charge.

8 Conclusion

8.1 Results

Take-or-pay pricing penalizes low capacity factor intermittent generators.
Low capacity factor generators have a relatively low energy output for their capacity. Under take-or-pay pricing, a generator's transmission costs are based on capacity, while revenues are based on output. If output is low compared with capacity, transmission costs can eat up a proportionately large share of revenues. And, if a generator is intermittent, it cannot pass through the majority of these costs with peak-hour markups as other generators will. There are alternatives to take-or-pay contracts; however, these do not provide a solution if a generator is unable to control or predict electricity output precisely. Wind and solar generators are among those penalized by take-or-pay contracts.

Access charges should be separated from congestion charges.
In a competitive market, price is equal to marginal cost. Applied to transmission, marginal cost pricing provides proper incentives for the use of the network, but cannot be used to recover the fixed costs of the transmission network. Thus when one charge is used to recover all the costs of the transmission provider, marginal cost pricing cannot be used. Assessing a separate access charge exclusively to cover fixed costs allows congestion to be priced competitively.

We acknowledge that firm capacity reservation must be sold on a take-or-pay capacity basis, but this charge should only cover congestion. Since fixed costs account for 80 to 90 percent of total network costs, the take-or-pay portion of transmission rates could be reduced by a factor of five or ten. Separating the charge allows us to consider alternative pricing structures for the access charge portion of the tariff, while still using take-or-pay for the much smaller firm capacity charge.

Access charges should be energy-based.
The split-off access charge should be restructured as an energy-based charge. Such a charge leads to the least-cost technology mix by eliminating the unfair and uneconomical burden placed on intermittent generators by the present capacity-based access charges. In addition, since energy-based charges can be passed on to customers under marginal cost pricing, they do not lead to the kind of market problems caused by capacity-based charges, which will be passed on either through scarcity rents or market power.

8.2 Future Work

8.2.1 Intermittence and Capacity Factor

Although the work on intermittence is quite far advanced, it will not have an impact on the design of transmission tariffs until it becomes widely understood and accepted. To achieve this currency we must accomplish two varieties of tasks:

1) Explore the many complications that we assumed away for the sake of getting to the heart of the design problem quickly and understandably.

2) Present this work in an understandable and accessible form to many interested audiences.

The first group of tasks entails answering questions raised in this report, such as assessing the impact of the two styles of access charge in a market characterized by significant market power. It also entails answering the many questions that will inevitably be raised as this work is presented.

The second group of tasks has even more importance. The suggestions contained in this report are quite fundamental, and although we believe that energy-based access charges are simpler than the current capacity-based charges, changing perspectives will still be quite difficult for many of those used to the current system. The question of designing the access charge is moot until two fundamental changes occur: (1) congestion charges are separated from access charges and (2) congestion is handled through competitive pricing. Achieving acceptance of such a fundamental shift in perspective by the broad audience that participates in these decisions will be extremely difficult. For that reason we believe that this issue must be brought before both FERC and a broader audience.

8.2.2 Network Expansion and the Distance Problem

This paper has taken the network as fixed and asked how one should charge for its use in a way that maximizes the efficiency of its use and encourages optimal investment in generation. We have ignored the problem of incentives for network expansion. While it is sensible to tackle the simpler short- and medium-run problems first, it is necessary to understand the very-long-run problem of grid investment before we can be sure of our results. Although this is an extremely difficult problem we hope to shed some light on it in our next report.

Basically, transmission investment can be carried out either collectively or privately. That is, when a line is built it will either be financed by those who intend to make use of it, or it can be financed by a tax or charge imposed on all those who are defined to be part of the network that is being improved. An example of private investment would be the construction of a radial line by a renewable generator that served only that generator. An example of a collective investment would be the upgrade of a major long-distance path used by many loads and generators or the addition of a line in a heavily meshed portion of the network.

Unfortunately the dividing line between expansions that should be collective and those that should be private is not clear. This can be extremely important to renewable generators who are sometimes situated at some distance and on lines which have an ambiguous character.

The central problem in this area can be described as follows. If we attempt to fully privatize investment, we run into the free-rider problem. That is, because lines that are privately built become part of the public grid, they may benefit those who have not paid for them. These free riders, because they do not contribute, always cause under-investment relative to what publically most beneficial. If we instead attempt to fully collectivize investment, this will eliminate free riders, but then there will be no disincentive for loads and generators to locate very remotely, for they know the cost they impose in the form of grid expansion will be largely borne by others.

There seems to be a natural compromise which consists of building lines collectively but charging the user according to the length of the path that they use. This is the aim of megawatt-mile schemes and of rate pancaking. But these schemes have been criticized (with considerable justification) for their negative impact on competition.

We have reviewed the literature in this area and found absolutely no consistency of viewpoint. In our next report we will attempt to untangle this problem at least enough to assess its impact on our conclusions regarding the benefits of an energy-based access charge. If possible we will also resolve the question of how much of the burden of remoteness should be borne by renewable generators.

8.2.3 Charging Loads

In Appendix C, we briefly assess the impacts of levying access charges on loads rather than generators. We argue that charging loads is equitable for all generators, whether the charge is energy or capacity based. However, we have not assessed the effect of such a charge on *loads*, so we cannot yet answer the question of whether charging loads is desirable.

REFERENCES

Benivedes, D. 1995. Pacific Gas and Electric (PG&E). Personal communication, December.

Bohi, Douglas R. 1981. *Analyzing Demand Behavior: A Study of Energy Elasticities*, Baltimore, MD: Johnsopkins University Press for Resources for the Future.

Bonbright, J. C. 1961. *Principles of Public Utility Rates*, Columbia University Press.

Chao, H. and S. Peck 1996. "A Market Mechanism for Electric Power Transmission." *Journal of Regulatory Economics*, vol. 10, no. 1, July, pp. 25-60.

Ellison, C., A. Brown and N. Rader 1996. "Scoping Paper on Restructuring-Related System Operation and Transmission Issues." Prepared for the National Wind Coordinating Committee. DRAFT. September.

FERC 1996a. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, Order No. 888, FERC Stats & Regs.

FERC 1996b. *Capacity Reservation Open Access Transmission Tariffs*, Notice of Proposed Rulemaking, FERC Docket No. RM96-11-000, April 24.

CCEM 1996. *Initial Comments of the Coalition for a Competitive Electric Market*, filed with FERC October 21, 1996, under Docket No. RM96-11-000, the NOPR on Capacity Reservation Open Access Transmission Tariffs.

Greene, N. 1996. "The Effects of Transmission Pricing on the Cost of Electricity from Renewables." Master's Project. Energy and Resources Group, University of California, Berkeley. May.

Harvey, S., W. Hogan and S. Pope 1996. "Transmission Capacity Reservation Implemented Through a Spot Market with Transmission Congestion Contracts." *Electricity Journal*, vol. 9, no. 9, November, pp. 42-55.

IndeGO, 1997. "IndeGO Pricing Report," IndeGO Pricing Work Group, March 18. From the IndeGO WWW site: www.idahopower.com/ipindego1.htm.

Mistr, A. F., Jr. 1996. "Incremental Cost Pricing: What Efficiency Requires." *Public Utilities Fortnightly*, January 1.

Porter, K. 1996. "Open Access Transmission and Renewable Energy Technologies." National Renewable Energy Laboratory Topical Issues Brief NREL/SP-460-21427. September.

Rosen, R., and S. Bernow 1994. "Electricity Transmission Pricing." Tellus Institute, Boston MA. September.

Wakefield, R.A., H.D. Limmer, D.J. LeKang and J.S. Graves 1995. *Transmission Services Costing Framework. Volume 2: Framework Description and Application*. Prepared for the Electric Power Research Institute (EPRI) TR-105121-V2 Research Project 3216-01. April.

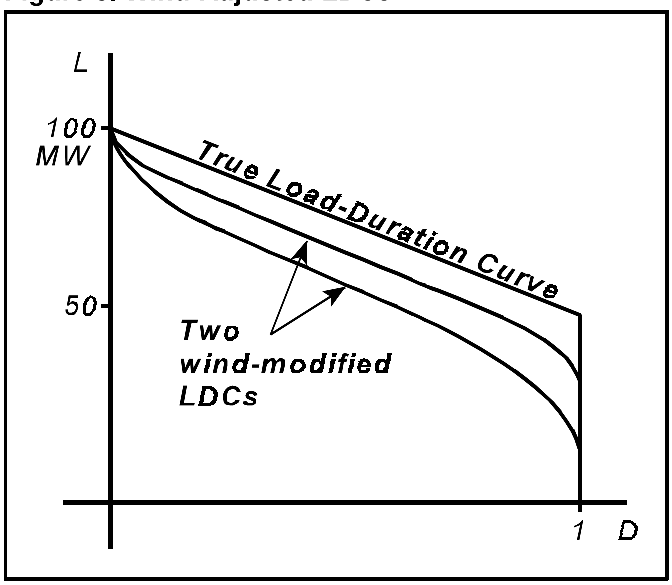
Walton, S. and R. Tabors 1996. "Zonal Transmission Pricing: Methodology and Preliminary Results from the WSCC." *Electricity Journal*, vol. 9, no. 9, November, pp. 34-41.

Appendix A: Intermittent Generation and the Least-Cost Technology Mix

Unlike the standard technology and the zero fixed cost technology, there is no economic decision to be made about when to use wind energy. At our assumed value of zero marginal cost, it should always be used when available. Because of this property, it can be viewed as a negative load. That means we can use it to modify the load duration curve (LDC). Unfortunately this is quite complex, so we will not be able to carry it out in complete detail as would be most satisfying. Fortunately, we can show what needs to be shown.

Wind generation produces its own, albeit negative, load duration curve which must be combined with the true load-duration curve. Because load duration curves are actually probability distribution functions (plotted with probability along the horizontal axis) they must be combined using the same rules used to combine probability distributions. This process is quite complex even when the distributions are uncorrelated. However, simple intuition can tell us enough about the qualitative results of combining wind generation with our simple load duration curve.

Figure 3. Wind-Adjusted LDCs

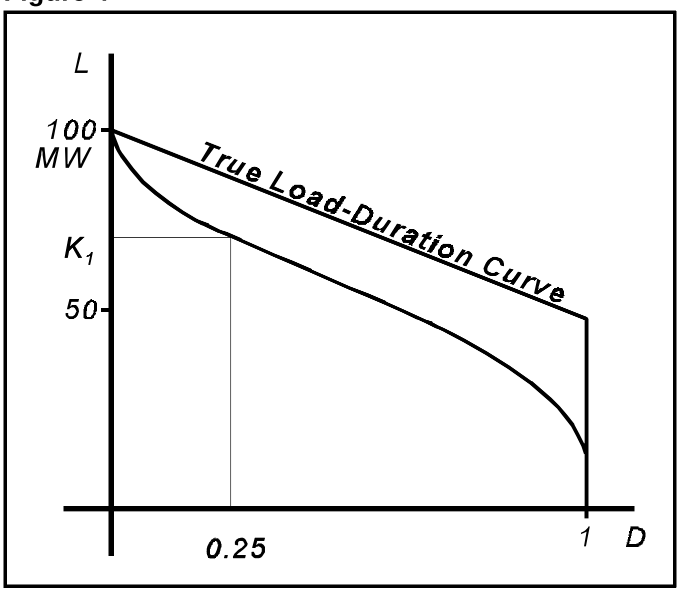


Assume we have a 10-MW wind generator that we wish to factor into the load-duration curve. We can imagine that the true LDC (see page 34) represents a daily fluctuation in load from 50 MW to 100 MW and back again that happens at a constant ramp rate in each direction, with no time spent in reversing directions. Now imagine that the wind generator fluctuates in output from 0 to 10 MW, spending more time at the low end. Because we have assumed zero correlation, wind will sometimes produce zero output at the system peak, so the combined LDC will have just as high a peak at the true LDC. By the same logic, at the system minimum load, wind generation will sometimes be at its maximum. This will reduce the combined load by 10 MW, so we know the combined LDC will be lower by 10 MW at the *Duration = 1* point on the LDC.

We can also get some idea of how the LDC must behave between these two extremes by considering wind's capacity factor. If wind generation has a capacity factor of 20%, then we know that the 10 MW of capacity will lower the LDC by exactly 2 MW on average. With this in mind we can draw qualitatively two modified LDCs, shown in **Figure 3**, corresponding to different capacities of wind generation. We now turn to the problem of finding the least-cost level of wind capacity, which fortunately does not depend on the modified LDC.

We have investigated both the standard technologies and wind technology independently and it is time to combine the two. Fortunately the interaction is minimal. The least-cost level of wind capacity depends on the weighted average price, which in turn depends on the duration of use of peak capacity. In our example this is 25%, so wind makes $80/MWh 25% of the time and $40/MWh 75% of the time. Fortunately these durations are determined by the cost functions of peak and base-load technologies and not by the load duration curve. Even though the LDC is affected by wind, this does not affect the load durations covered by peak and base loads. So in fact we have already correctly solved for peak duration and wind capacity. All that remains is to solve for peak and base-load capacities.

Figure 4



Capacities can simply be read from the modified load duration curve as shown in **Figure 4**. If $L_W(D)$ is the load duration curve modified for wind, then $K_1 = L_W(25\%)$ is the efficient amount of base-load capacity, and K_0 э 100 &K_1 is the efficient amount of peak capacity. As explained above $L_W(D)$ is too difficult to compute in this example, but we are only concerned here with showing general properties of the least-cost selection of technologies.

Appendix B: A Capacity-Based Charge Raises Only Peak Prices

When peaking technology achieves a higher price in the new post-tax equilibrium, we would expect this to change both the load duration curve and the cutoff duration D_0, so we will define a new post-access-charge LDC, $L^A(t)$, and a new cutoff duration, D_0^A. By defining a markup, m(t), valued in $/MWh, as a function of duration, t, we can now write the zero-profit condition for the peak technology:

$$\int_0^{D_0^A} [\, L^A(t) - K_1 \,]\, m(t)\, dt = A \cdot [\, \max(L^A) - K_1 \,] \tag{13}$$

where A is the access charge and $\max(L^A)$ is the system peak load. The left side is the profit that will be made on the markup, and the right side is the access charge times the peak-load capacity. We next divide both sides by peak-load capacity.

$$\int_0^{D_0^A} \frac{L^A(t) - K_1}{\max(L^A) - K_1}\, m(t)\, dt = A \tag{14}$$

Because the fraction is always between zero and one, we know that

$$A = \int_0^{D_0^A} \frac{L^A(t) - K_1}{\max(L^A) - K_1}\, m(t)\, dt \le \int_0^{D_0^A} m(t)\, dt \tag{15}$$

Multiplying by K_1, the capacity of base-load technology gives

$$A \cdot K_1 \le \int_0^{D_0^A} K_1 \cdot m(t)\, dt \tag{16}$$

This means that the total access charge on base-load capacity is less than or equal to the total profit collected from the peak-load markup while peak-load capacity is in use. Remember that any increase in price achieved by peak-load capacity is an increase in market price and applies to all kWh sold during those hours. This means that base-load capacity will automatically recover the capacity tax during peak hours without raising its price during base-load hours. If there were any tendency for base-load capacity to gain market power or an increase in scarcity during the base load hours, this would raise base-load profits above zero, bring entry to the base-load market and drive prices back down during the base-load hours. So we have proven the following:

The Capacity-Tax Result: A capacity tax falls on peak-load users and does not increase prices during the base-load hours.

This does not quite clear up the outcome of a capacity-tax, though it is as much as we really need to know. Equation **(16)** shows that base-load capacity could actually be more profitable once peak-load has adjusted to the tax than it was before. In this case, base-load capacity will increase beyond its optimum level. The other possibility is that equality could hold in equation **(16)** and there would be no distortion in technology choice. This would happen only if the fraction in equation **(15)** were 1 whenever m(t) > 0 and zero whenever m(t) = 0. This describes the case of scarcity without market power. In this case, there is a flattened peak on the load duration curve at the level of total system capacity, and load is held to this level by price escalating above marginal cost. With this outcome all technologies earn zero profits and there is no distortion in the market's selection of technologies. For the pure scarcity case, equation **(16)** implies that the average value of m(t) over the range from 0 to D_0^A is given by:

$$\overline{m(t)} \ni A / D_0^A \qquad \textbf{(17)}$$

Appendix C: The Effect of Charging Loads for Transmission Access

So far we have assumed that generators will pay the access charge and this is traditional practice. But California's WEPEX has recommended that the access charge be assigned instead to loads. In this appendix we examine briefly the differences between charging generators and charging loads. Once again, our perspective of an access charge as a tax and the examination of the incidence (burden) of that tax is crucial.

In Section 6 we learned that all generators would pass an energy-based charge on to their loads, while all but intermittent generators would pass on a capacity-based charge. Thus, the entire problem with the capacity-based charge can be summarized as an inability of intermittent generators to pass on their access charges to their loads.

This problem is completely resolved by assessing charges on loads instead of generators. In this case, even a peak-based charge will be fair to intermittent generators such as wind and solar. This conclusion is not quite as obvious as it looks. Just as with a tax on generators, a tax on loads is not necessarily borne by the loads that pay the tax. For instance, in a market with bilateral contracts, if loads paid a higher access charge when contracting with wind or solar generators than with other generators, the extra tax would be passed from the loads back to the generators. The wind or solar generators would bear the extra tax paid by their loads. The competitive market enforces this outcome. Loads would never choose to contract with a wind or solar generator unless that generator agreed to pay the tax (or equivalently reduce its price).

So, how can we be sure that an access charge placed on a load is actually borne by that load and is not passed back to the generator? This result follows if the access charge paid by the load is unaffected by its choice of supply generator. In other words, if the load pays the same access charge independent of which generators it contracts with, then the burden of the charge cannot be shifted. Since most load profiles will not depend on where the load buys its power, the access charge paid, whether it is peak-based or energy-based, will not depend on the load's choice of supplier. Therefore, the charge cannot be shifted.

There is one small exception to this argument and to our conclusion that loads could not shift the burden of the access charge back onto the wind or solar generator. This exception proves that our argument and our conclusion is non-trivial. If wind or solar generators find that they are penalized for their intermittence by a market that needs predictability, they may seek out and find special loads that have a high tolerance for the erratic nature of their output. A pumping station may be such an example. These loads may be willing to pay nearly full price for wind- or solar-generated power. With enough such customers, wind or solar could raise its price/kWh to nearly the market price of power. However, if a peak-based access charge is placed on loads, then the generator's special customers will suddenly find themselves penalized for trading with the wind or solar generators. This is because when they buy from an intermittent generator their use of power approximately follows the output of the generator and thus fluctuates much more than it would if they bought from a non-intermittent generator. Because the peak-based access charge makes it expensive for them to buy from a wind or solar generator, that generator must effectively pay their extra access charge or lose them as a customer. In this way the access charge will be passed back to the generator.

The above example is contrived in several ways. It assumes that there are loads that will significantly modify their demand profiles to accommodate wind and solar generators, that there are enough of these to purchase the entire output of all intermittent generators, and that wind and solar generators cannot otherwise sell their power at the market price. We do not believe that this is at all a realistic description of the market faced by wind generators. We have presented this example to make two points. First, an access charge on loads could, in principle, be passed back to generators in a way that would discriminate against wind. Second, this possibility should be considered highly unlikely. Therefore, we conclude that assessing loads for the access charge will prove equitable for all generators, even if the charge is a peak-based or capacity-type charge.

This conclusion does not mean that a peak-based charge on loads is desirable. We have not investigated its impact on loads. That problem is beyond the scope of this paper.