EXECUTIVE SUMMARY
QUANTIFICATION AND DEVELOPMENT OF MARGINAL COST BASED ELECTRIC RATES— THE PERTURBATION METHOD*

By

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Financial support for this research came from the Florida Board of Regents, through the Public Service Commission. Support also came through a Department of Energy contract to the Florida PSC on Metering for Innovative Rates (PURPA, Section 461.32(3)). Points of view herein expressed do not necessarily represent the official position of sponsoring or cooperating orgainizations. The numbers in this report are for illustrative purposes only; they are unsuitable for rate hearings for several reasons. The baseline forecast, the system plan, and other key factors have changed since the initial calculations were made in August 1979. In addition, assumptions made in calculating rates to different customer classes need to be modified in light of recent (and on-going) load research.

Abstract

QUANTIFICATION AND DEVELOPEMENT
OF MARGINAL COST BASED
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This study reviews the economic rationale behind marginal cost based rates and calculates time-of-use costs for an electric utility. Five basic methodologies for calculating marginal costs are briefly compared, but only one is actually applied. The Cicchetti-Gillen-Smolensky (CGS) approach to the perturbation method is applied to Florida Power Corporation for 1979. Marginal costs are estimated for two broad seasons (April-October and November-March), during peak and off-peak hours, for weekdays and weekends. Energy and capacity costs are calculated for two voltage levels. We then test the sensitivity of the results to alternative assumptions about interest rate, reserve margin, price of capacity, and hours in the peak. A suggested modification to the CGS method used to recalculate capacity costs. The steps for translating costs into rates are then discussed and the original CGS costs are used to develop marginal cost based electric rates which yield the same revenue per customer class as the actual 1979 rates.

Acknowledgements

As part of a program to encourage university researchers to address issues identified by state agencies as involving significant public policy impact, the legislature has provided research funds to the Florida University System Board of Regents STAR program for several years, with energy issues receiving a high priority for funding. This project on the quantification and development of marginal cost based electricity rates represents a $16,878 investment in the collection and analysis of information for the improvement of government decision-making. The study draws upon research supported by the Public Utility Research Center in past years, and would not have been possible without the close co-operation and assistance of the Florida Power Corporation. The Florida Public Service Commission is currently considering innovative rate structures for electric utilities. This report is offered as a contribution to rational debate in this complex policy area.

The co-authors share jointly the responsibility for the analysis and conclusions presented herein. Practicing what we preach, the principle of comparative advantage and the resulting division of labor caused much of Brockman's time to be spent on gathering the appropriate numbers for calculating time-of-day costs, and learning to apply existing software packages for making calculations. Berg's contribution is in the interpretation and the discussion of economic principles. Both authors analyzed the results, tested the reasonableness of the input data, and suggested modifications to the perturbation method. Points of view herein expressed do not necessarily represent the official position of sponsoring or cooperating organizations. Each co-author blames the other for any ommissions.

Many people have assisted in gathering necessary numbers and reviewing the computation procedures. Dr. Daniel Czermanski of the National Regulatory Research Institute was very helpful in providing background information. Special thanks go to Wallace Baron and Bill Slusser of Florida Power Corporation for their tolerance of unreasonable requests on their time. Others at FPC who have helped us appreciate the complex issues involved in this area include Randy Hayes, Tom Raines, L'Mar Kane, John Simpson, Henry Southwick, George Marks, and Bob Bowles.

This Report is addressed to the Florida Public Service Commission. James Gentry (formerly Research Director at the FPSC, now Research Director, Rate Design at TVA) got the project off the ground; Bill James (current Director of Research) and Mary Bane brought it to earth, and Dave Swafford (Executive Director, FPSC) saw that we did not exceed the excess baggage requirements. We are deeply grateful to these and other Public Service Commission staff members for the guidance they have provided. However, they take no responsibility for the results presented here. Finally, Department of Energy contract to the Florida PSC on "Metering for Innovative Rates" provided additional research funding for dealing with the costing issues.

EXECUTIVE SUMMARY
QUANTIFICATION AND DEVELOPMENT OF MARGINAL COST BASED ELECTRIC RATES: THE PERTURBATION METHOD

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If the economic benefits of moving to time-of-use (TOU) pricing exceed the associated metering costs, then adoption of marginal cost based electric rates will enhance economic efficiency. TOU rates also promote fairness in that off-peak consumers no longer pay for costs incurred to meet the demands of peak consumers. To derive marginal cost based TOU rates, decision-makers must select appropriate costing methodologies, particularly for calculating marginal generation costs. This study both applies and critiques the perturbation approach to calculating marginal costs, to assist regulators and utilities in their evaluation of associated TOU rates.

Chapter 1 first describes the PURPA policy initiatives and economic theories national debate over marginal cost pricing. The rationale behind marginal cost based rates is essentially that customers and producers ought to bear the cost-consequences of their decisions. Economic efficiency is promoted when customers continue to purchase a good (or service) up to where the marginal benefit to the consumers equals the marginal cost of production (the additional resources given up by society to produce the last unit of output). Under uniform pricing (based on historical or embedded costs), there is underproduction during off-peak hours and overproduction during peak hours. The resulting misallocations can be characterized in terms of lost potential benefits to consumers.

The consumer benefits of TOU rates increase over time, as customers are able to adjust their stock of electricity-using appliances and to purchase timers and other devices. Thus, residential, commerical, and industrial

customers will be more responsive to price changes as the adjustment time lengthens. Capacity additions to meet growth in peak demand are then delayed, resulting in reductions in revenue requirements. To obtain these savings, regulators must evaluate marginal costs, which requires agreement on a number of conceptual and measurement issues. One conceptual issue is whether short run or long run marginal costs are more appropriate. Should price signals reflect the additional cost to society of additional production today (given the existing level and mix of generating capacity), or the additional cost to society of the additional output _if_ the firm were allowed to vary all inputs, including the generation mix? The former costs are highly volatile for electric utilities, so that pricing on the basis of short run costs may confuse customers, rather than assist them in making wise consumption decisions. If price includes a capacity component, the consumer receives a price signal that better reflects the long run implications of additional consumption at peak times.

Peak load (or TOU) pricing recognizes that the cost of service (calculated in a number of ways) is higher during certain seasons and at certain times of day. A utility would not charge a uniform price at all times of the day, irrespective of costs. A higher price would be in effect during peak hours, when costs were relatively high, while lower prices would be offered during off-peak hours when the cost of service is low. Of course, movement toward such a pricing structure would require investment in time-of-day meters.

The last part of Chapter 1 surveys five of the well-documented alternative methods for calculating marginal costs, with marginal generation costs representing a major source of disagreement. Some view the existence of alternative marginal costing methodologies as involving a contest or race in which there can be only one "correct" methodology. The authors of this study do not agree. In swimming, for example, both the butterfly and the

breast stroke will get the contestant across the pool. While a "serviceable free style" might be the goal of marginal costing practitioners, it may be that a kind of relay involving several strokes is best. There appears to be instances where one methodology fits better than another, depending on the circumstances and data availability of the particular utility. Only time and experience can provide answers to these issues. One thing we know for sure: sinking is not swimming. Similarly, an embedded cost methodology is not going to give efficient price signals.

One difference among methodologies is whether capacity additions are viewed in a historical context, in which an actual firm is altering its existing plant optimally over time, or whether additions are being made to a firm whose generation mix is being planned de novo. The former conception is used in the Cicchetti-Gillen-Smolensky (CGS) version of the perturbation methodology, while National Economic Research Associates (NERA) adopts the latter standard. Both perturbation approaches look at the effects of variaations in the load curve from the viewpoint of the system planning engineer. Both recognize that shifts in the load curve (due to price changes or other factors) change the expansion plan; thus the incremental costs are net costs of the shift plus (minus) any other costs (savings) directly attributable to the load change. The CGS technique sometimes takes the next movable base load unit (or units) as the marginal capacity, while the NERA technique usually has peaking units (combustion turbines) represent marginal generating capacity. CGS takes the cost of capacity as the "cost of advancing or delaying units in the construction schedule to meet a change in demand...(with the)...cost allocated equally across all hours of the peak period using loss of load probability and judgement to determine the peak period" (p. 1-16). Three other methodologies are briefly described in the first chapter. The Ernst & Whinney and Gordian approaches adopt the de novo and historial conceptions

respectively, of long run marginal cost. Both methods differ from the CGS and NERA perturbation approaches by drawing more heavily on econometrics and computer modeling. The E & W technique draws from neoclassical economic theory and estimates a production relationship, in order to estimate a cost function. Gordian, like CGS, includes the variable cost of the existing system, and unlike CGS, uses a linear programming optimization model. A fifth methodology, proposed by Ebasco Business Consulting Company (EBBCo) is essentially a short run marginal cost calcultion; instead of calculating a capacity cost, EBBCo finds the price needed to limit quantity demanded if the reliability criterion is not to be exceeded. In equilibrium, and in the absence of indivisibilities, change, and uncertainty, these various approaches are not mutually inconsistant.

We do not endorse any particular methodology, but chose to apply the CGS perturbation technique to Florida Power Corporation because it was readily available, well-documented, and accepted by many practioners as basically sound. The main benefit of the project may have been its role as a catalyst in bringing together technical personnel (such as systems planners, rate designers and economic analysts) from state utilities and the Florida Public Service Commission. When such individuals consider a concrete situation which includes some of the special characteristics of a Florida utility, they are less likely to view marginal cost pricing in abstract terms. Having a particular methodology applied to FPC allows all the assumptions and approximations to be catalogued and analyzed in the context of Florida rate-making and allows the reader to much more easily understand the distinguishing features of any marginal costing methodology.

Chapter 2 describes in detail the steps and calculations necessary in the CGS perturbation approach. There is a capacity (or demand charge) portion of the peak period marginal cost, a marginal energy charge (which may differ between peak and off-peak periods) and a marginal customer charge. Reserve margins, line losses, the cost of capital, and other factors are taken into account in the analysis. The basic types of data are listed below:

1. "Opportunity cost of capital" to the firm, used to calculate the annualized one year cost of moving generation facilities forward. It should be a weighted average of monies the firm borrows plus return on equity, taxes, etc.

2. Number of years over which to ammortize plant, also used in calculating annual capacity costs. It presents no problem to utilities since they already depreciate plants over some lifetime.

3. Transmission and Distribution system losses by voltage level, used to increase demand and energy cost to account for losses. These data are needed both on and off-peak. They can usually be obtained only for a few of the voltage levels present on a system (from power flow studies).

4. Either historical or future T & D expansion plans and cost for a period of time long enough to smooth out any lumpy investments not due to load growth.

5. A forecast of peak demand for a period of time corresponding to (4).

6. The future generation expansion plans of the utility, which are usually readily available as a published document. Cost of future facilities is also needed.

7. The estimated fuel savings from moving a plant forward a year, which may be obtained from production simulation runs or estimated by operators.

8. The fuel and O & M costs by period for existing plant or that existing at time for which marginal costs are being calculated. Methods similar to (7) are used.

9. An estimate from system planners as to which plants and facilities would be moved.

The chapter concludes with a brief discussion on the selection of the peak and of off-peak periods. Statistical techniques can be used to group

production costs and consumption patterns on the basis of homogeneity. In addition, the likely customer responses need to be taken into account to avoid peak shifts. Narrowly defined rating periods are probably inappropriate, given possible instability of costs, KW demands, and energy usage.

The next chapter applies the CGS perturbation method to Florida Power Corporation to derive marginal costs for 1979. Since the purpose of the calculations is solely to test and give information on the workings and sensitivity of the CGS approach, the results are preliminary and illustrative. The rating periods, load forecasts, systems plan, and proposed alterations (to meet perturbations in the load) would all differ today (April 1980) from the numbers used in making these calculations (July/August 1979). A second reason why the results presented in Chapter 3 would be inappropriate for a rate case is that much more precise estimates and detailed documentation is necessary for regulatory purposes.

After quantifying the variables described in Chapter 2, this chapter proceeds to derive marginal costs for Summer (April-October) and Winter (November-March), both peak and off-peak, and for weekends and holidays. The results for the base case appear in Table 3-6. Because of lower line losses and reduced distribution requirements, the marginal costs for these five periods are lower at the transmission level than at the distribution level. At the latter level, we obtain over a four to one differential between peak and off-peak periods. The generation capacity charge is the major determinant of this cost differential.

To test the sensitivity of the CGS approach to changes in the basic input assumptions, several tests were conducted and the effects analyzed. Different generating units were assumed moved, the opportunity cost of capital was varied, the reserve margin was lowered, and the number of hours in the peak period was modified. The sensitivity results are presented in Table 3-7.

Chapter 4 explores some anomalies of this application of the CGS technique to FPC. Although the CGS perturbation method does parallel the actual planning process of the utility, CGS point out that moving a particular generating unit forward one year may not make economic sense. For example, a utility could respond to a change in load by negotiating long-term purchases from other utilities. In such instances, the marginal cost would be the price paid under those new contracts. Although this alternative was not considered in this study of FPC, it certainly is a relevant alternative.

The results we obtained in applying the CGS technique to FPC lead us to question whether the marginal costs of moving a base load unit forward one year were not in fact too great to justify choosing that alternative over a lower cost one (such as purchasing power for a year). Reflections on the planning prices revealed that unless the load forecast was incremented enough to justify moving the unit, then sufficient fuel cost savings would not accrue to make this option economically viable. The authors, therefore, recommend that if the CGS technique is used, the load be be incremented enough in the production simulations to justify the move. FPC was asked to run new production simulations incrementing the load; the fuel savings increased from $3.9 million to over $39 million, which would reduce the marginal generating capacity cost.

Our experience with FPC data strengthens our view that one should not use a software program or particular methodology uncritically when calculating the marginal cost of electric power. Instead, one must first compare the situation to the assumptions of the method. When the situation and the assumptions do not correspond, the methodology may have to be expanded to

incorporate additional features. Only when careful scrutiny has been given to the interpretation of the numbers can the results be successfully defended as reasonable approximations to marginal costs.

In Chapter 5, the principles of rate design are reviewed and then illustrative TOU rates are derived for FPC, based on the previous cost calculations. The issues in applying TOU rates are discussed, especially the time pattern of implementation. For example, the cost of meters can be expected to decline in real terms over time. They will also become more flexible and sophisticated. Investments in meters today imply some foregone gains in the future. But certainly for large users, this problem is moot, since those opportunity costs are unlikely to outweigh the current benefits of reduced capacity requirements and improved fuel efficiency. For residential customers, however, a wide range of load management devices are becoming available; TOU pricing, interruptible rates (load management), and hybrids complicate the choice. Current investment in meters implies a reduction in flexibility for the future, although without the load research (made possible by the meters) future investment plans (and rate designs) will lack necessary information.

The chapter also notes that rate derivation is an iternative process. If energy (and capacity) demand were both very responsive to price, the movement to marginal-cost based rates would be expected to cause revisions in a utility's ten year expansion plan. Unless price elasticities were taken into account by rate-makers, the new marginal-cost based rates derived the following year, based on the new expansion plan incorporating the dampened demand growth, would have to be changed--perhaps dramatically. Sensitivity test should be performed in anticipation of such developments.

Such considerations suggest that rate design will continue to be an "art" based on informed judgment. However, the information framework from which the judgments will be made is vastly superior to the embedded data used in the past.

Bonbright's traditional rate-making objectives are discussed in terms of a transition to TOU rates. The following eight goals are discussed: (1) simplicity and public acceptibility, (2) freedom from controversy, (3) revenue sufficiency to earn a fair return, (4) revenue stability, (5) rate stability, (6) fairness in apportionment of total costs, (7) avoidance of undue rate discrimination, and (8) encouragement of efficiency. Illustrative rates are then calculated for six classes (or groupings): Residential, general service--non-demand metered class, general service--demand metered class, miscellaneous, street-lighting, and largest industrial users. A key constraint in the construction of these rates involved holding the class contribution to what it was prior to TOU rates. In addition, for simplicity, only three broad periods were utilized: Winter peak, non-winter peak, and off-peak.

The class contribution constaint meant that a surplus (or deficit) when marginal cost rates were charged had to be made up through a customer credit (or charge). Alternatively, rates could be adjusted, taking into account demand elasticities and ignoring the class contribution constraint. Inelastic demands would experience the relatively largest price shifts, since they minimize resource misallocations. We did not attempt to analyze or comment on the relative mix of burdens within a customer class--a necessary step for a rate case. We did, however, introduce short-run demand elasticity considerations. The resulting rate structures (shown

in Tables 5-2 through 5-7) do not include a KW charge for groups now being demand metered. It might be that during some transitional period, such rates would be retained. Further study in this area is necessary.

The concluding chapter reviews some comparisons of the different methodologies and underscores the limitations of this preliminary investigation. These observations are summarized below:

(1) The calculation of a capital recovery factor is dependent upon permitted rate of return, taxes, anticipated inflation and technological change, and other variables. Given the importance of this factor, care must go into its derivation.

(2) Use of annualized (or levelized) capacity costs does permit comparisons of benefits and costs, but some observers view it as loading costs at the front end of the time period--especially if short-run opportunity costs are taken to be the ones relevant for pricing purposes.

(3) The calculation of marginal transmission and distribution capacity costs was very crude. Problems arise when using either historical extrapolations or marginal plans. More work needs to be done in this area.

(4) The calculation of a customer charge (for the basic distribution system and hookup, billing, etc.) was left up in the air, as was its translation into rates. In our example, we assumed that hookups were unresponsive to monthly charges, but this revenue adjustment approach has implications for the variability of utility cash flows.

(5) The selection of rating periods is a very complex process. Periods of long run (or short run -- system lambda) marginal cost homogeneity may be determined by judgment, cluster analysis, LOLP or other techniques. The various competing methods offer some insights into this area. Due to data limitations, different rating periods were used for calculating costs and for determining revenues in deriving our rates. This inconsistancy needs to be corrected.

(6) The choice of long run over short run marginal costs is judgemental. Characterizing situations where one or the other appears to be more appropriate should receive high research priority.

(7) CGS perturbations involve lumpiness in generation additiona. Should costs be treated "as though" there were more flexibility, so the unit cost of capacity would not rise with smaller additions?

(8) Given the range of uncertainty associated with both input prices and load forecasts, a number of plausible scenarios should be run

for rate case purposes, so that the range of outcomes (and associated rate structures) can be carefully delimited.

(9) The inclusion of a metering charge in the TOU rates raises the issue of appropriate depreciation. Anticipated technological changes would justify rapid depreciation (and high monthly charges) since current meter investments imply that future opportunities will be foregone. On the other hand, one can argue that utilities are gaining information about customer behavior under TOU rates, which benefits all customers. Thus, especially if TOU rates are voluntary, lower monthly charges might be more appropriate.

(10) The calculation and role of fuel adjustment charges has not been given much attention in this study. This issue will need to be addressed for rate-making purposes.

(11) The marketing of TOU rates will be a key determinant of ultimate consumer acceptance. This report does not address this important topic.

Several implementation issues are then discussed, including the implications of TOU pricing for the conservation of energy. In addition, phasing in TOD rates and partial implementation raise the issue of discrimination--both across and within customer classes. The metering cost makes time-of-day (TOD) rates uneconomical for low use customers. Optional rates which reflect the costs (and savings) associated with TOD rates may be adequate to solve the potential discrimination problem. Some penalty charge for maintaining the prior (uniform price) status might be called for since some cost is imposed on other electricity users when small users do not conserve on the peak. Finally, "second best" issues are addressed in the context of rate-making. We conclude that such considerations can be ignored for pricing in the electricity sector, just as they are ignored in our antitrust policies.

Movement away from fully allocated cost based prices would not jeopar-

dize the financial viability of electric utilities. We believe that it is important to separate the process by which total revenue requirements are determined from the process by which efficient and equitable price structures are selected. To meet the former objective, we recommend policies ensuring that electric utilities have the financial strength to attract capital to maintain current levels of service and meet future demand. The permitted rate-of-return necessary to ensure financial strength is determined through hearings and the presentation of evidence. The revenue requirements, on the other hand, can be met through a variety of price structures; however, some cost allocation schemes can promote inefficiency. Just as regulators must now weigh alternative testimony on the exact rate-of-return to be permitted to a utility, they are likely to be weighing evidence on the basis for pricing structures. Here we have attempted to build a case for marginal cost based pricing, and for the development of costing techniques which can move us in this direction.

We acknowlege the technical assistance of many individuals from the Florida Public Service Commission and Florida Power Corporation. However, the analysis and points of view expressed herein do not necessarily represent the official view of sponsoring or cooperating organizations. This study is offered as an addition to the growing body of analysis in the important area of marginal cost-based electric rates.

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QUANTIFICATION AND DEVELOPMENT

OF MARGINAL COST BASED ELECTRIC RATES -

THE PERTURBATION METHOD