EFFECTS OF ALTERNATIVE ELECTRICITY RATES AND RATE STRUCTURES ON ELECTRICITY AND WATER USE ON THE COLORADO HIGH PLAINS

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COLORADO WATER RESOURCES

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ABSTRACT

The largest agricultural consumer of energy in Colorado is the pumping of groundwater for irrigation, primarily in the 600,000 acres of pump-irrigated land overlying the Ogallala aquifer region of eastern Colorado. The Ogallala formation is a largely non-renewing supply, so the incentives and disincentives which affect pumping also affect the life and productivity of the aquifer.

This study used computer models of a representative quarter section of irrigated land to estimate the demand for electricity and pump irrigation water and to analyze the effects of various rate structures on farm resource allocation and income. The models were adapted from a linear programming model used in the Colorado portion of the Ogallala-High Plains Study. Profit-maximizing behavior was assumed for the operator of a typical irrigation well, which implies that the user will purchase electricity so long as incremental returns exceed incremental costs. Seventy-four alternative electricity and water using production processes are used to represent the irrigators production choices and resource productivities.

Crop prices are found to be the most important factor affecting farmer response to electricity rate structure, so that analysis was performed for two price scenarios. Using January 1982 crop prices, demands for electricity and irrigation water were found to be sensitive to electricity prices in the 7 to 9 cent per kilowatt hour (kwh) range, which is in the range of present average cost. Rate structures using a relatively low hookup charge and higher energy charge would encourage conservation by causing a shift in the crop mix from corn to irrigated wheat. Similarly, single block and increasing block rate structures encourage less irrigation than the more prevalent declining block rate structures. The model predicted farm income to remain relatively stable with conversion to less energy intensive crops, but this result came at the expense of utility revenues.

Seasonal rate structures, which incorporate discounts of up to 30 percent for off-peak energy use, did not shift predicted peak demands under either price scenario. (Load management programs were not tested.)

The demands for electricity and water for irrigation were much more inelastic under the 1977-1981 average crop price scenario. These relative prices were about 25 percent higher (in real terms) than the 1982 price scenario. Rate structures would have less impact on farm resource use, should commodity prices again rise to that level. If these low prices were expected to persist, model forecasts imply a rather substantial decline in electricity demand from irrigators.

The principal policy recommendation is a call for change in the form of sharply declining rate blocks. Concern is raised that the last block reached by most customers does not meet the long-run incremental costs of providing energy and that the user cost of Ogallala water is ignored. An increasing block rate structure ending at long-run marginal cost of acquiring additional electricity offers the advantages of meeting revenue requirements and increasing conservation incentives. Allocative efficiency could be improved to a lesser degree by the alternative of lowering hookup charges and using single block or very gradually declining block rate structures. Allowing electric cooperatives to average irrigation revenue over several years would facilitate the latter type of charge.

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INTRODUCTION

Energy, water, and agriculture are each important public concerns in Colorado. The largest agricultural consumption of energy in Colorado is for the extraction of groundwater for irrigation, particularly in eastern Colorado. There, water is pumped to irrigate about 600,000 acres of land. The water is withdrawn from the Ogallala aquifer, an ancient deposit of saturated sands and gravels underlying a large portion of the High Plains. The aquifer is recharged by precipitation to only a small extent, so the incentive and disincentive forces which govern withdrawal affect the potential life of the resource.

Public policy, in the case of regulated industries such as the electrical utilities, can influence the <u>level</u> and <u>form</u> of prices (rates) charged to consumers. Any particular combination of rate level and rate form is referred to as a "rate structure." The structure of charges to energy users can affect consumption patterns and has an impact on whether users conserve the resource or use it wastefully. For example, a structure for which the marginal charge is low encourages consumption, whereas a rate with a high marginal charge can promote conservation. Since the energy consumed is used to pump and apply water for irrigation, there is a direct link between energy prices and water use. Rate structure changes are hypothesized to influence the date of the aquifer's exhaustion. Even small differences in aquifer life will be important to individuals and communities directly affected.

Natural gas and electricity prices, in addition to groundwater regulations, commodity prices, and interest rates, are among the most important factors affecting the future of irrigation in the High Plains. These two sources of energy are used in 98 percent of all Colorado High Plains irrigation. The deregulation of natural gas is expected to increase its price substantially in the region over the next 10 years. Because of this and because electric motors are generally less costly to maintain and repair than natural gas engines, electricity is expected to be the dominant source of irrigation power in the future.

The effective price of electricity for irrigation is determined by two factors: the rate structure and the hookup charge. The rate structure specifies the charges per kilowatt hour (kwh) in each block of energy used. In a declining block rate costs per kwh are highest for the first block of power used, and less for each successive block. Much of Colorado High Plains irrigation powered by electricity is now under a declining rate structure. Several rural electric associations (REAs) in the region are considering adopting a single block structure that will charge the same amount per kwh regardless of the amount used.

In addition to costs from the rate structure, a charge may be made for each motor that is hooked up to the system. A charge of $20 per horsepower per year is typical, so the hookup charge for a 100-horsepower motor is $2000 a year -- before a single kwh of energy is used. Add in the cost of actual power use -- $7000 per year for a center pivot system irrigating 130 acres is typical -- and the total annual bill can be $9000 per circle or $70 an acre.

The combination of declining block rates and high hookup charges provide less incentive for either energy or water conservation than do alternative structures. Under these pricing policies, the last kwh used costs much less than the first, and so the last acre inch of water applied also costs less than the first. This encourages farmers to raise crops that require more water.

From the utility company's perspective, these pricing policies were developed to insure sufficient revenue to cover fixed costs associated with power plant and transmission systems. These policies have worked well to provide revenue in the face of uncertain future electricity use. Under these policies, a relatively large amount of revenue is generated from initial hook-up fees and initial uses of power, since the first block is the most expensive per unit. In this way, utilities have some protection against the possibility of major declines in electricity usage. Unfortunately for irrigators, if total energy use in the region begins to decline, utilities will have to increase their hookup charges per kwh annually to maintain revenues, and the "reward" for saving energy could be a rate increase.

The pricing policies of electric utilities -- local REAs -- have an important effect on energy and water use efficiency and on the life of the Ogallala aquifer. It will be difficult to balance the interests of all parties involved: irrigators want cheaper energy so they can continue to irrigate; utilities need sufficient revenue to supply electricity; and <u>all</u> citizens of the region have a stake in sustaining the economic life of the aquifer.

Objective and Plan of Study

The policy issue with which this study is concerned is: What electricity rate structure policies for pump irrigation are in the long-term interests of the suppliers, the users, and the public? Economic analysis cannot provide the entire answer to this question. However, forecasts of the impacts of alternative rate structures on energy consumption, water use, farm production, and net income will provide valuable insights to aid in rate structure decisions. The purpose of this study is to provide conceptually sound and factually-based forecasts of these impacts. We are aware of no previous study explicitly directed to the role of rate structures in pump irrigation economies.

The following section provides some theoretical background on rate structure analysis and the demand for electricity. Then the model used in the analysis, which was adapted from the previous research of the Ogallala High Plains Study, is described in detail.

The analytic approach is most easily explained as a set of computer modelling experiments which isolate different aspects of rate structures. First, an empirical demand curve for electricity for irrigation is derived from the model, assuming the adoption of a single block rate. Then the effects of varying the proportions between the hookup charge and a single block are examined. Variations in declining block rate structures are the next topic studied. Finally, a seasonal rate structure with a winter discount is modeled. The results of this research, combined with utility pricing theory, are then used in a comparison and analysis of existing rate structures for irrigation in eastern Colorado.

CONCEPTUAL FRAMEWORK

In this section, we briefly dicuss the criteria for rate structure evaluation, review several common rate forms, and develop the concepts of demand and cost which are utilized in the subsequent analysis.

Criteria for Evaluating Rate Structures

Several criteria can be used to evaluate rate structures, including allocative efficiency, revenue sufficiency, equity, ability to pay, and resource conservation [Hirshleifer, DeHaven, and Milliman, 1960].

Allocative Efficiency

The most important criterion for the purpose of this study is that of "allocative" or "economic" efficiency. This criterion is concerned with attaining maximum net value of product from the economy's scarce resources, given the level of technology and preferences of consumers. Economic efficiency is obtained when the marginal price to the consumer is equal to the marginal cost of producing an extra unit of the commodity (so-called "marginal cost pricing"); maximum net returns are achieved. The rational consumer will limit purchases to the level where the net benefit of the last unit of electricity just equals the cost of supplying that unit. Any consumption less than this point has marginal value greater than cost, so that such an output level is less than optimal. Similarly, consumption in excess of the point of equality of incremental benefit and incremental cost implies that cost exceeds value of the margin, which is wasteful of resources. (This concept is developed in more detail in the next section. See Figure 5 and related text.)

Revenue Sufficiency

The main yardstick by which rate structures for public utilities have historically been measured is their ability to raise enough revenue so as to meet operating costs, provide an adequate return on capital, and thereby render the utility financially self-sufficient [Gardner, 1977].

Equity

Another traditional belief is that rate structures should be set so as to recover the full cost of the commodity from the user. Sometimes called the "beneficiary principle," this criterion views the payment of part of the costs of serving one user group by charging another group more or by the general taxpayer as inequitable. Discrimination in the charges to different customer groups is regarded as equitable only if the cost of service varies between or among the groups [Turvey, 1971].

Ability to Pay

A criterion often in direct conflict with the one just described would differentiate according to wealth and/or income, such that low income groups would pay less per unit than the financially better off. "Lifeline" rates for the elderly or the poor is a well-known example. The level of the consumer's ability to pay must be set by a subjective judgment on the part of the regulatory authority, since there is no known objective rule for such cases.

Resource Conservation

In an ideal economy, where all commodities and services are priced at their incremental cost, where the future is fully known and interest rates reflect the appropriate discount of future consumption against present usage, the price system would serve to conserve resources and allocate them optimally through time. However, in a real world in which groundwater is unpriced and there exists a suspicion that the true scarcity value of fossil fuels and the external costs associated with their combustion are not fully reflected in fuel prices, some observers have looked to electricity rate structures as a means of encouraging conservation of unpriced or improperly priced water and energy resources. The effective price of scarce resources should ideally include the "user cost," which is the present value of opportunity cost of sacrifices imposed on future users by consumption in the present [Howe, 1979].

Resolving Conflicting Criteria

The criteria described above are at times in conflict. However, ready resolution may be found in some cases, while others require social or political decisions on appropriate tradeoffs.

Perhaps the most widely described conflict is between allocative efficiency and the revenue requirement. In the case of decreasing costs, marginal cost will be below average cost at the preferred level of output, so that marginal cost price will fail to satisfy the revenue requirement. In such event, a service charge reflecting fixed costs or higher rates for the first units of electricity, combined with rates reflecting marginal costs of subsequent consumption will satisfy both criteria [Berg, et al., 1976]. The equity objective is also satisfied by two-part pricing systems of this sort, since the full cost of electricity supply is paid for by the user.

Common Rate Forms

Only general statements about rate forms need be made at the outset. (See Taylor [1975] for a particularly detailed review of alternative rate forms and their impacts.)

Flat Charge

Under this rate form, each customer pays one total price for any amount of electricity consumed. There is no limit to the amount used. There is also no incentive to conserve electricity because the marginal cost of consuming another unit is zero. This rate form is used for municipal water or sewer services, but not for electricity. (See Figure 1)

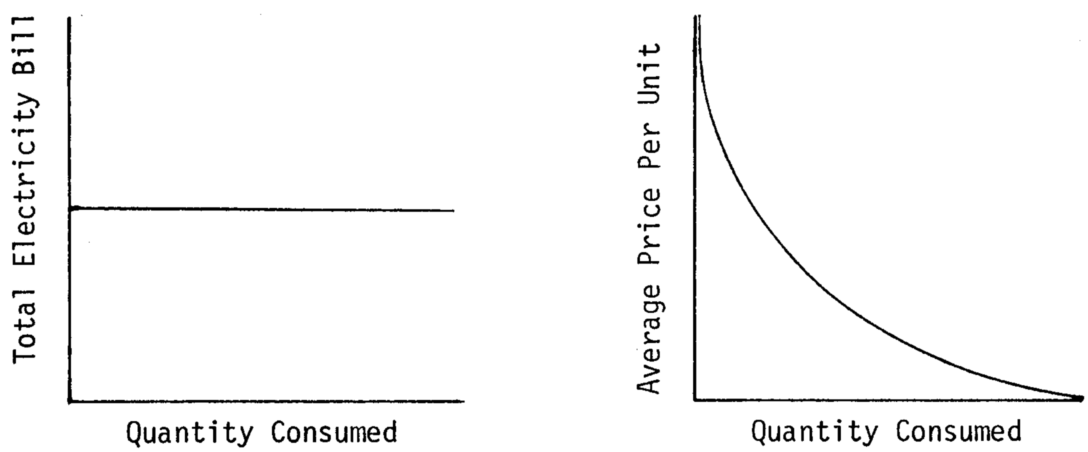


Figure 1. Total Electricity Bill and Average Prices - Flat Charge

Single Block

Here the price per unit of electricity is constant no matter how much electricity is consumed. Total cost to the consumer increases with consumption, so there is an incentive to conserve. Since there is only one price, this incentive remains constant. If the single block is set to match marginal cost, this rate form can be both efficient and nondiscriminatory. Varying costs for different consumer classes means a variety of single block rates, however. Of course, there must be some sort of metering system to measure consumption. (See Figure 2)

Declining Blocks

The price per unit in this rate form decreases in a stepwise manner with the amount purchased. The consumer pays one price, or rate level, for a

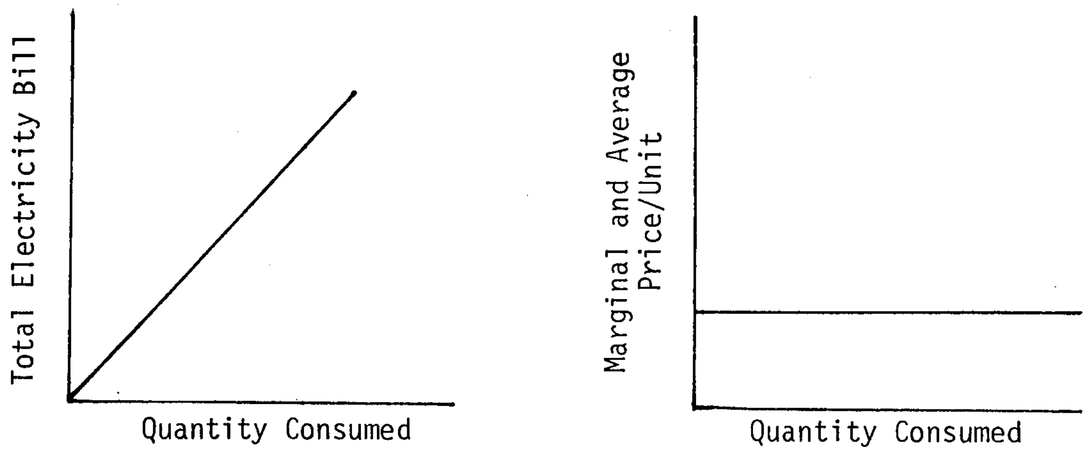


Figure 2. Total Electricity Bill and Marginal and Average Prices: Single Block

specified quantity of electricity and lower prices for succeeding units of consumption. The total cost increases, but at a decreasing rate. (See Figure 3) Since incremental costs fall with increasing consumption, the incentive to conserve similarly declines as lower rate levels are reached.

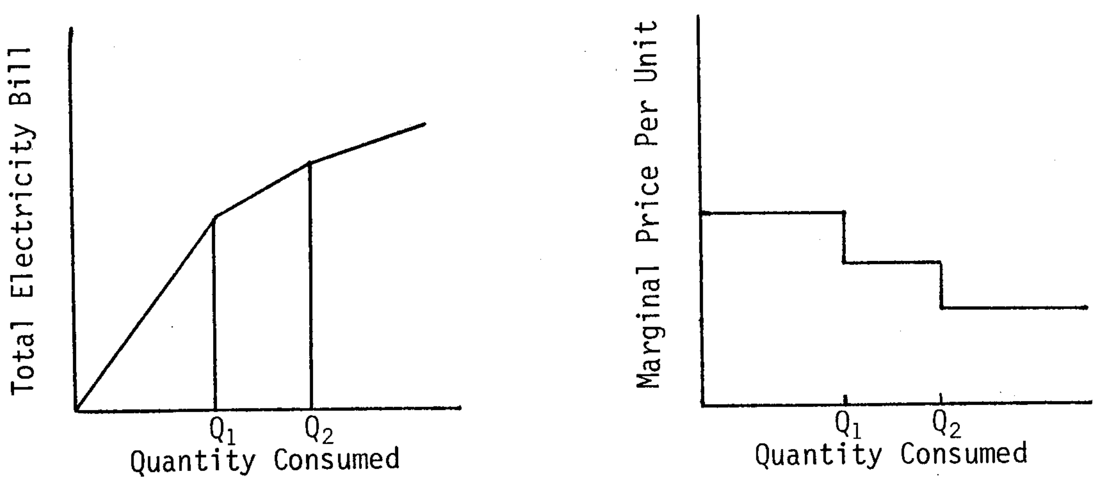


Figure 3. Declining Block Rates

The rate levels that are attached to the declining form are very important. If all customers reach the lowest price and it is set at marginal cost, this rate form can also be efficient. The higher rate blocks would then serve only to capture enough consumer's surplus from inframarginal consumption to meet revenue requirements and would not affect resource allocation. However, if the first blocks are set above marginal cost so as to allow later blocks to be below marginal cost, declining blocks encourage overuse of electricity.

Increasing Blocks

This is the opposite of declining blocks in that the price per unit increases in a stepwise fashion with the amount purchased. The total cost of electricity increases at an increasing rate. (See Figure 4) The incentive to conserve increases as higher rate levels are reached. When the cost of new generating capacity is large, this rate form can be used to discourage peak demands. If the last block's rate equals long-run marginal cost, increasing block rates can be efficient in allocation and avoid a short-run revenue surplus. It is also the rate form proposed as "lifeline" rates, which offer minimal amounts of electricity at a nominal cost.

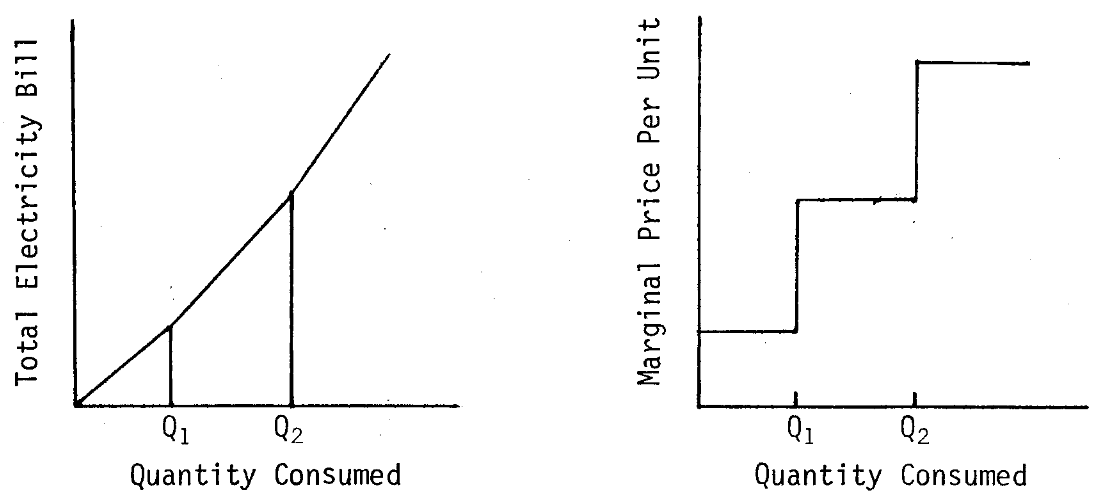


Figure 4. Increasing Block Rates

Time-Dependent Forms

Several of the above forms may be given added refinement by adding variations in level (and form) with respect to time. This may vary between seasonal structures, which shift two or more times yearly, to day of week shifts, to hourly shifts. These types are termed "peak-load pricing" systems, and are often advocated as rationing mechanisms for periods of high general energy demand [Wenders, 1976; Crockett, 1976]. Such structures require a much more sophisticated means of measuring energy quantity. Meters with the necessary capabilities are being rapidly perfected and are not at all infeasible in the current and anticipated state of technology.

The Demand for Electricity and the Marginal Cost of Acquiring It

To facilitate analysis of farmer behavior under different rate structures, additional economic concepts are introduced. The principles of supply and demand provide decisions rules regarding the amount of electricity a rational, profit-maximizing farmer will purchase.

Consider the simple resource allocation model in Figure 5. The demand curve shows the amount of a good that an individual would purchase at varying prices. The curve is downward sloping because the price one is willing to pay decreases as quantity increases. The horizontal line shows the price (P) at which unlimited quantities of the good are available. It is labeled MC for the marginal cost of acquiring another unit. In more realistic examples, marginal cost need not be constant or horizontal.

In the short run, the marginal cost curve is also the supply curve for the good. Thus, the intersection of marginal cost with demand at A illustrates the familiar economic principle: supply equals demand at the optimum quantity. If the example represents a farmer's demand for electricity for irrigation, then he purchases Q kwh at a price P per kwh. The farmer does not purchase more than Q because he is not willing to pay the marginal cost of acquiring it. Nor does he purchase less than Q units because those units are worth more to him than their price. In fact, since the demand curve

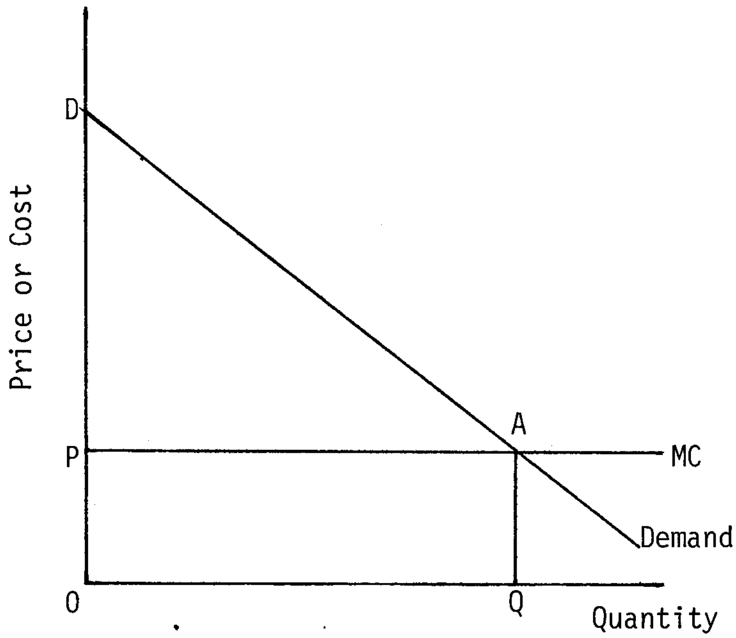


Figure 5. A Simple Resource Allocation Model.

represents willingness to pay, the farmer has actually reaped excess benefit in the amount of the triangle $\overline{PDA}$ from this transaction. This area under the demand curve but above the cost paid is called consumer surplus. The farmer paid an amount equal to the rectangle $\overline{PAQO}$ which becomes revenue to the producer of electricity. (In the case under study, electricity is an input to a production process — a producer's good — and is represented by the Value of Marginal Product (VMP). The surplus in this instance represents the producer's profit [Heady, 1952].)

In the case of electricity, the fixed costs of investments in power generation and transmission facilities are often much larger than the operating cost of producing power. In an attempt to cover these costs, utilities often assess a hookup or demand charge to irrigators prior to delivery of a single kwh. Since the farmer can purchase as much electricity as he likes, and the utility must maintain extra capacity for that contingency, the hookup charge can be viewed as the price of the privilege of entering the market [Hirshleifer, et al., 1960].

A hookup charge can be construed as taking from the farmers' surplus. As long as this fixed charge is less than the consumer surplus generated by planned consumption, theoretically, it will not affect a farmer's irrigation decisions. However, if the hookup charge does exceed the surplus, the farmer won't irrigate at all. These two cases are illustrated in Figures 6a and 6b. One should remember that demand curves will vary among farms, due to productivity differences, so that a particular rate structure might cause some to cease irrigation while leaving others unaffected.

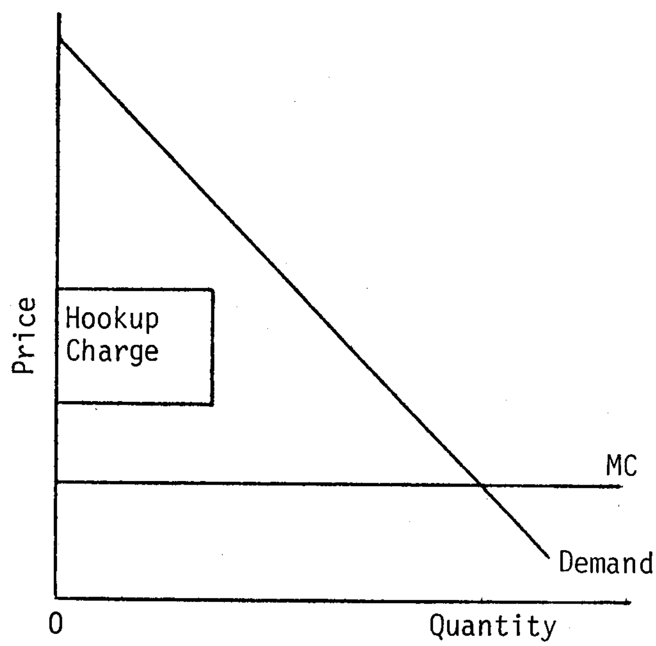


Figure 6a. Single Block Rate with Hookup Charge

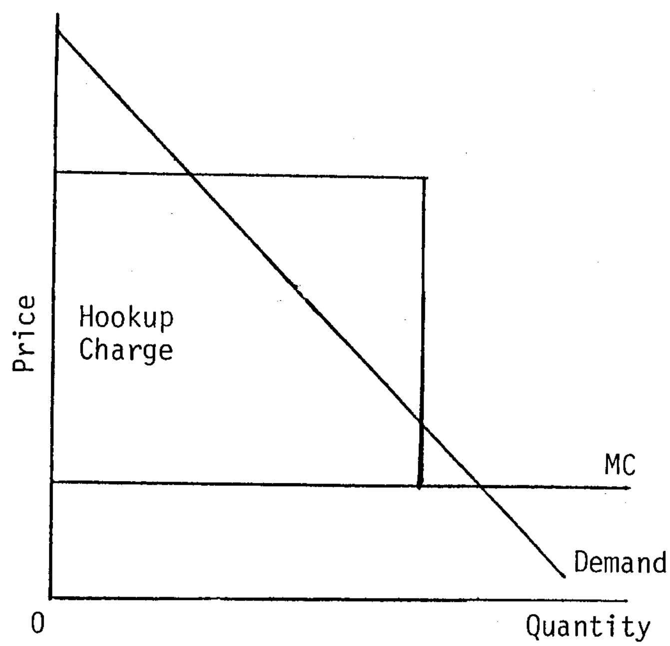


Figure 6b. Single Block Rate with Excessive Hookup Charge

Another pricing strategy used by electric utilities instead of a hookup charge is to charge higher rates for the first kilowatt hours and then make successive consumption cheaper. This is, of course, the declining block rate structure, and its aim is to pay fixed costs by capturing a part of the consumer surplus through the variable charge [Crockett, 1976]. Figure 7a shows that the effect is to change the marginal cost curve. It is now discontinuous in that a higher price applies until the end of that block is reached at Q_1, whereupon the next lower price is used for the next unit. It is theoretically possible to construct a rate structure, such as in Figure 7b, which takes away most of the consumer surplus, yet still does not affect user decisions. This would maximize utility revenues. In practice, however, the variations in consumer demand and the uncertainties in estimating demand makes this type of rate structure very risky. It might result in a situation as shown in Figure 7c where a block crosses the demand curve, creating multiple optimal solutions. A rational farmer might purchase Q* units, or he might purchase out to Q** if his consumer surplus covers the area where costs exceed demand. Holding consumption to Q* could wreak havoc with utility revenue estimates.

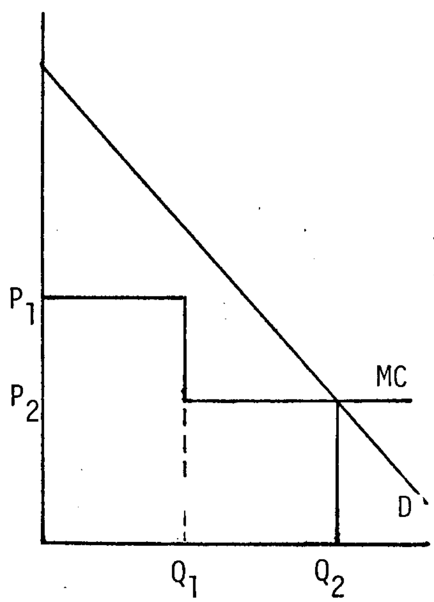


Figure 7a. Declining Block Rate Structure

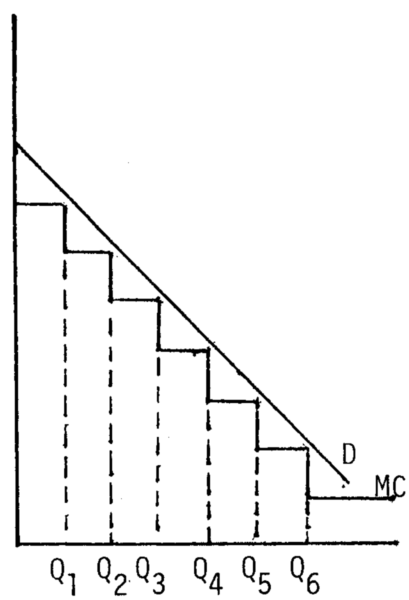


Figure 7b. Declining Block Rate Structure

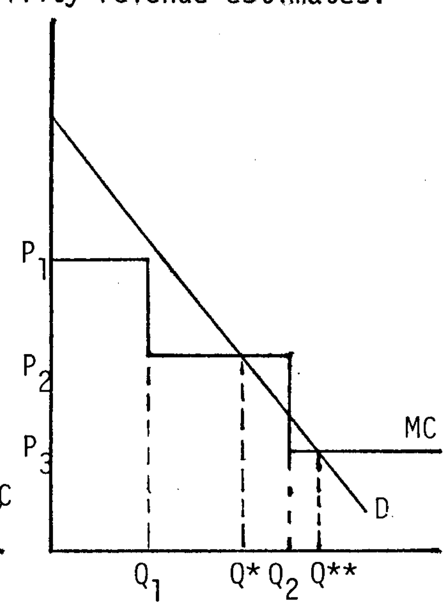


Figure 7c. Declining Block Rate Structure with Multiple Solutions

Thus, it can be seen that the most important variable in a rate structure is the marginal cost at the point where demand is intersected. This factor determines the amount of electricity purchased. Provided there is sufficient surplus to cover the hookup charge and there are no multiple solutions, the number of blocks and the way they change will not affect the behavior of users of electricity.

It should be noted that the term marginal cost in this discussion has referred to the marginal cost facing the consumer for purchasing another unit. This marginal cost is determined by the rate structure, which is easily changed. The most efficient allocation of resources will occur if the relevant marginal cost is also the marginal cost to the utility of producing that unit (though there is debate whether this should be short-run or long-run marginal cost. See Turvey [1971] or Saunders, Warford, and Mann [1977]). A declining block structure could still be efficient if its last block reflected the utility's marginal cost and was attained by all customers. As Cowing [1980] states

> To summarize our discussion, the efficiency condition for optimal rate structures requires that the price in the last or marginal block be set equal to marginal cost, and that inframarginal prices be set neither so high that some consumers are forced out of the market nor so low that the firm cannot meet its allowed revenue requirements.

Finally, some mention should be made of factors which cause individual demands to differ and others which shift all demand curves. The demand by a farmer for an input such as electricity for pump irrigation is conceptually given by the value of the marginal product (VMP) of that input. An input will be used by the rational farmer until the VMP equals the input price. The VMP, of course, varies with the crop or crop mix grown and with soils and climate. The productivity of water depends, too, upon the levels of all the other inputs in the production process. Fertilizer and pesticide applications are examples. Management skills such as tillage practices and irrigation timing also affect the value of the marginal product of an input.

Some economic and physical factors cause a shift in all users' demands for an input. Crop prices affect the value of the marginal product of all inputs used on the farm. Similarly, changes in the price of other inputs will affect pump irrigation levels. Falling aquifer levels increase the amount of energy needed to pump and thereby raise water costs. Thus, any one, or a combination of, lower crop prices, higher prices for other inputs, or lower aquifer levels could cause the demand shift portrayed in Figure 8 which caused a reduction in electricity use from Q_1 to Q_2. While the following sections use increases in electricity prices to show farmer reactions, and hold all other factors constant, it is important to know that the effect could also have been brought by a change or changes in these other factors as well.

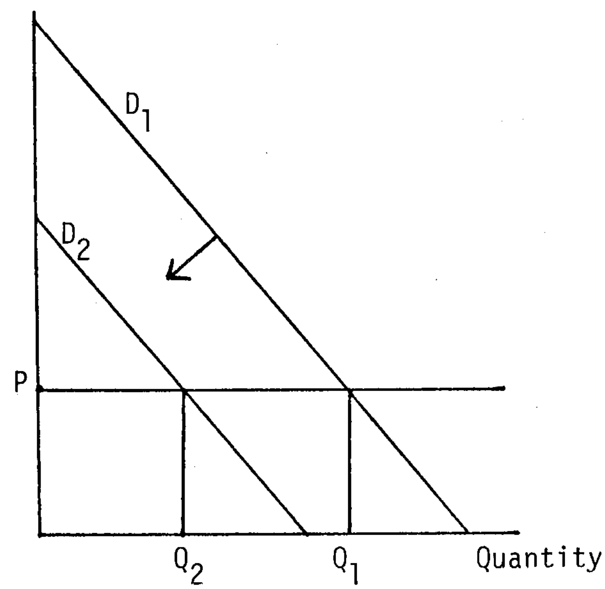


Figure 8. A Downward Shift in the Demand for Electricity

THE ANALYTIC MODEL AND THE STUDY AREA

To analyze the effects of various rate structures, the reactions of an economically rational High Plains farmer growing a typical irrigated crop mix with an average well are examined. The crop mix may be changed within allowable limits (determined by market or agronomic considerations) or less water and other inputs may be applied so that profits are maximized under each rate structure. A static linear programming model assesses these reactions.

The model builds upon a just-completed study of the long-term outlook for the six-state Ogallala aquifer region, supported by the U.S. Department of Commerce and the various state governments. The Colorado portion of this Ogallala-High Plains Study developed models to forecast energy and water demands in six subareas of eastern Colorado [Young, et al., 1982].

The crop budgets were based on a farm survey which was conducted by L. R. Conklin in the fall of 1979 to determine actual resource use, resource organization, and farming practices in the region. A random sample of 86 farm operators was interviewed. A linear programming model which optimizes returns to land and management was then constructed to simulate farmers' crop growing decisions for normal production practices, yields, and input and crop prices. (See Appendix 1 for a partial tableau of the model.)

While the model used here is thus based on reported 1979 farming practices, production technologies are not thought to have changed appreciably. Input prices were updated to January 1982 [Conklin, 1982]. Many input prices are reported for Colorado in the USDA publication, Agricultural Prices. In cases where prices were not specifically reported, an updated price was computed using the appropriate component of the USDA "Index of Prices Paid by Farmers." Seed and fertilizer prices were confirmed with retail suppliers.

Crop prices were also updated to a five-year average price expressed in 1982 dollars. However, since crop prices are so influential to the model results, and since commodity prices have fallen considerably the last two years, many of the tests were repeated using January 1982 crop prices for sensitivity analysis. Table 1 contains the resulting commodity and input prices, as well as normal yield assumptions.

Table 1. Commodity Prices, Yields, and Input Prices for Subarea 5 of the Ogallala Aquifer Region, Colorado.

	Unit	1977-1981 Average Price Per Unit (1982 dollars)	Jan. 1982 Crop Prices Per Unit	Irrigated Crop Yield (full irrigation)	Dryland Crop Yield
Commodities					
Sugar Beets	Ton	$43.40	$30.00	17.0	
Pinto Beans	Cwt.	28.60	14.00	16.0	3
Corn	Bu.	3.15	2.50	130.0	20
Wheat	Bu.	3.87	3.50	50.0	22
Sorghum	Bu.	2.70	2.10	75.0	20
Alfalfa	Ton	71.50	63.00	4.5	0.9
Selected Inputs					
Diesel Fuel	Gal.	$1.15			
Gasoline	Gal.	1.26			
Anhydrous Ammonia	Lb.	0.13			
Other Fertilizer	Lb.	0.15			

Six crops were included in the model: sugar beets, pinto beans, corn, wheat, sorghum, and alfalfa. It is assumed that these crops can be grown with any of three different irrigation systems: furrow irrigation employing gated pipe, or center pivot sprinklers using either conventional high pressure or low pressure nozzle systems. The crop could also be irrigated at "full" levels, as measured by the farm survey and expert opinion, or at reduced application rates of five-sixths, two-thirds, or one-third of full irrigation. (Wheat, however, was not differentiated to allow the five-sixths irrigation level.) This detail in the model allows more precise estimation of electricity and water demand. Dryland crop production was another option for all crops except sugar beets. The model therefore contains 74 crop activities.

Production conditions vary across the Colorado Ogallala. Time and resource limits precluded an investigation of all possible conditions, so the Burlington area was chosen for this case study. This subarea has reasonably homogeneous medium-textured soils, and includes the southeastern portion of Yuma County and eastern Kit Carson and Cheyenne Counties (see Figure 9). It is an area of low relative humidity and abundant sunshine with an average growing season exceeding 150 days. Average annual rainfall is 15 to 16 inches, but it is highly variable in timing and amount. Soils are generally loams or silt loams, and elevations range around 4,000 feet.

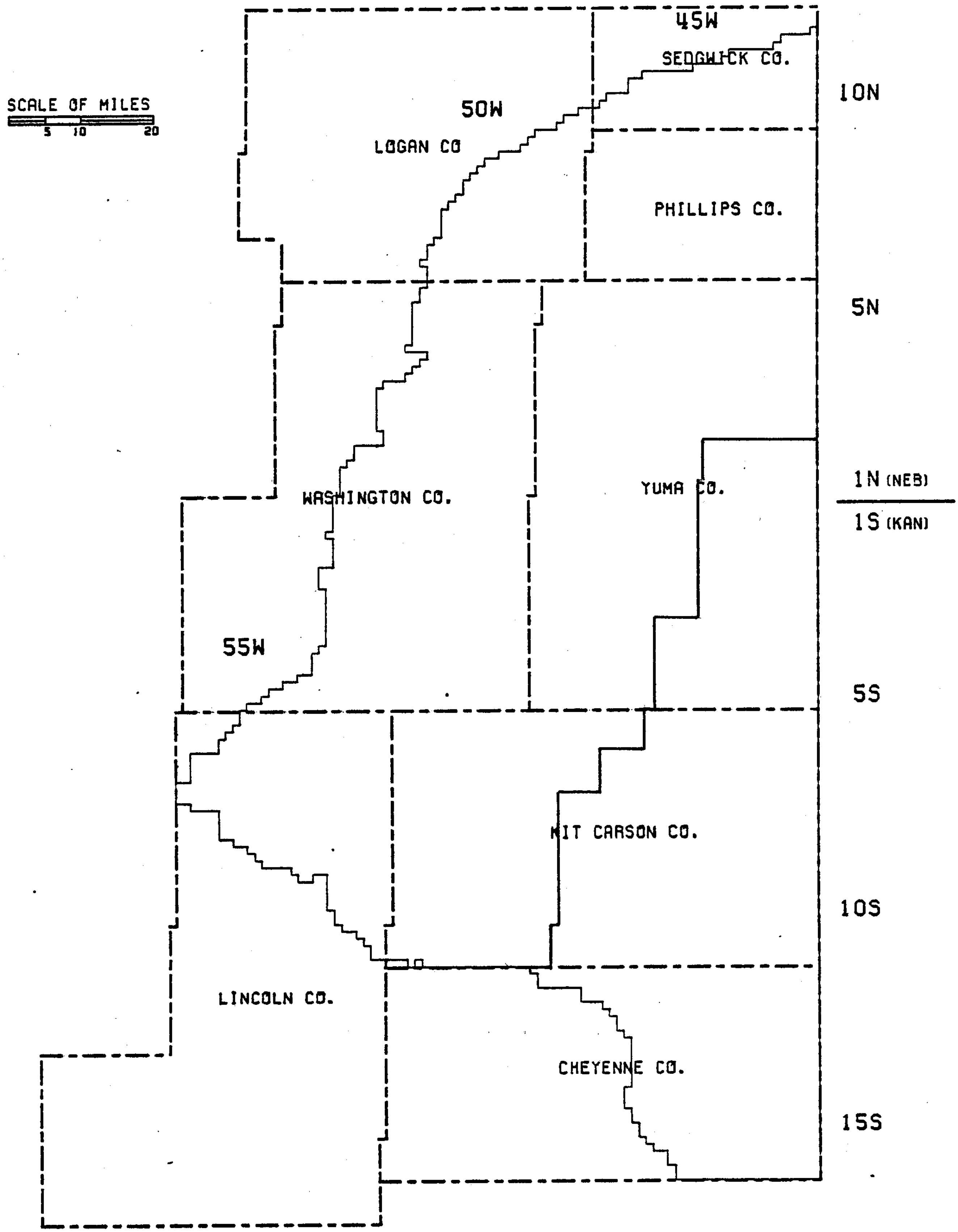
Extensive irrigation began in the 1960's with surface irrigation or row crops. Center pivots have been installed during the 1970's where topography discouraged surface irrigation. In parts of this area, the cost of pumping water has already dictated an increase in the acreage of crops less water-intensive than corn, such as small grains and pinto beans.

The model is based on the average well depth for the area in 1979 and the average irrigated area per well of 128 acres. Average 1979 pump lift (or depth to water plus drawdown) was 158 feet, and total dynamic head (TDH) was computed by the following formula:

TDH = Pump Lift + Column/Pump Head Friction + (2.31 ft/psi x Operating Pressure) + Elevation Head

where: Column/pump head friction = 12 feet,

Operating pressure = 5 psi for gated pipe,
40 psi for low pressure sprinkler,
75 psi for high pressure sprinkler, and



OGALLALA AQUIFER, NORTH-EASTERN COLORADO

Figure 9

Elevation head = 0 for gated pipe,
10 feet for low or high pressure sprinkler.

The total dynamic heads computed by this procedure and used in the model were 180 feet for gated pipe surface irrigation, 270 feet for low pressure sprinkler, and 350 feet for high pressure sprinkler operations. The model's estimates for electricity and water demand are thus for a hypothetical average well or quarter-section.

By the nature of linear programming, the most profitable activity would tend to be selected exclusively for maximum farm profits. Some constraints were necessary to simulate to a degree at least the physical and economic limitations that dictate the present farm operation mix. Since surface irrigation cannot be installed on sloping fields, gated pipe systems were limited to a maximum of half the irrigated area. Similarly, low pressure sprinkler irrigation was limited to half the acreage because this technology is not suited to heavy soils. Because of soils considerations, at least one-fourth of the land was forced to remain under conventional high pressure center pivot sprinklers as long as irrigation remained feasible.

Crop constraints were also considered necessary for sugar beets and pinto beans. These crops are the most profitable, but their limited markets prevent expansion of these crops to large areas. Sugar beets and pinto beans were therefore constrained in the model to the proportion of the crop mix they represent in Yuma and Kit Carson Counties, or about 5 percent each.

Finally, this model incorporates a medium-run planning horizon. It is not short-run because machinery fixed costs are included in the farm budgets in addition to variable input costs. However, a return to land, managerial skills, and irrigation systems costs are not included in the model. A separate test is therefore made for long-run irrigation feasibility by subtracting the opportunity cost of land (measured by returns to dryland wheat production), management costs of 6 percent of gross returns, and the annualized irrigation system investment cost from net income. The irrigation system cost is an average of gated pipe and center pivot system costs weighted by the existing proportions in subarea 5. The $78,100 system investment is amortized at 6 percent real interest for 20 years and amounts to $51 per acre per year.

THE ESTIMATED DEMAND FOR ELECTRICITY AND IRRIGATION WATER

Demand curves for electricity and irrigation water were estimated by first solving the model with a single block rate structure. The price of electricity was varied from 2 to 50 cents per kwh, while all other prices were held constant. Five year average, inflation-adjusted, commodity prices were used first.

Resource Demand with 1977-81 Average Prices

Demand for Electricity

As illustrated in Figure 10, the demand for electricity is a stepped function of its price as is characteristic of linear programming results. A particular crop mix might remain the most profitable as electricity increases in price until a new configuration maximizes net income. Thus, over short shifts in price, the demand curve appears to be inelastic, then highly elastic. In reality, the aggregate response to price would be more gradual both because individual farmers with differing production conditions would react at different price levels and because a diversified crop mix is preferred to sudden massive shifts.

The most pertinent characteristic of this empirical demand curve is that it is highly inelastic within the relevant price range. Price elasticity is only -0.019 in the range from 1.3 to 14.8 cents, meaning that a 1 percent increase in price would reduce consumption of electricity by only 0.019 percent. Since the blocks of nearly all rate structures fall within this range, this is an early indication that rate structures may not have a large effect on farmers at current electricity prices and average crop prices. However, at prices exceeding 14.8 cents per kwh, the demand for electricity is quite responsive, with elasticities approaching unity.

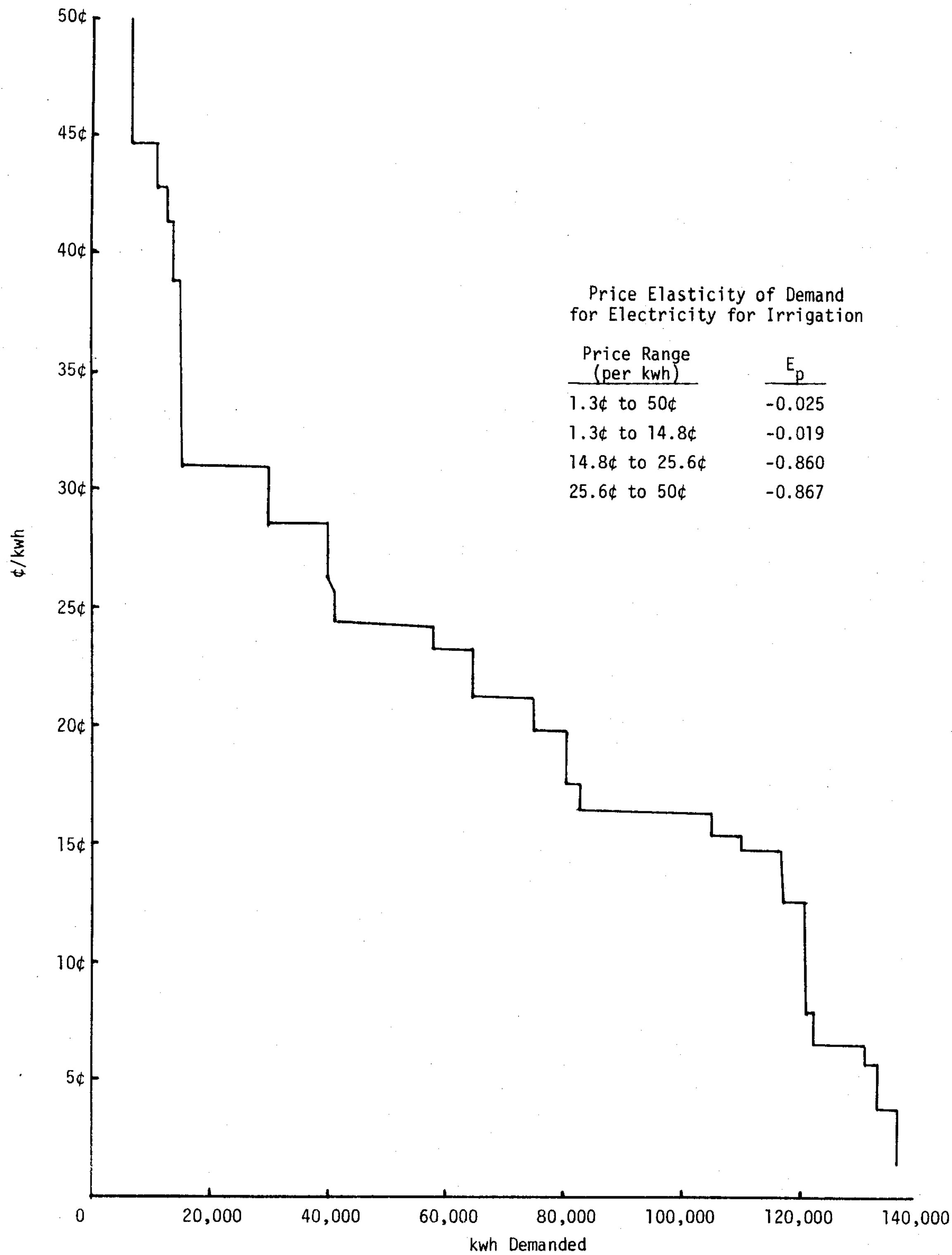


Figure 10. Estimated Demand Per Well for Electricity for Pump Irrigation with 1977-81 Average Commodity Prices.

"Cross" Demand for Water

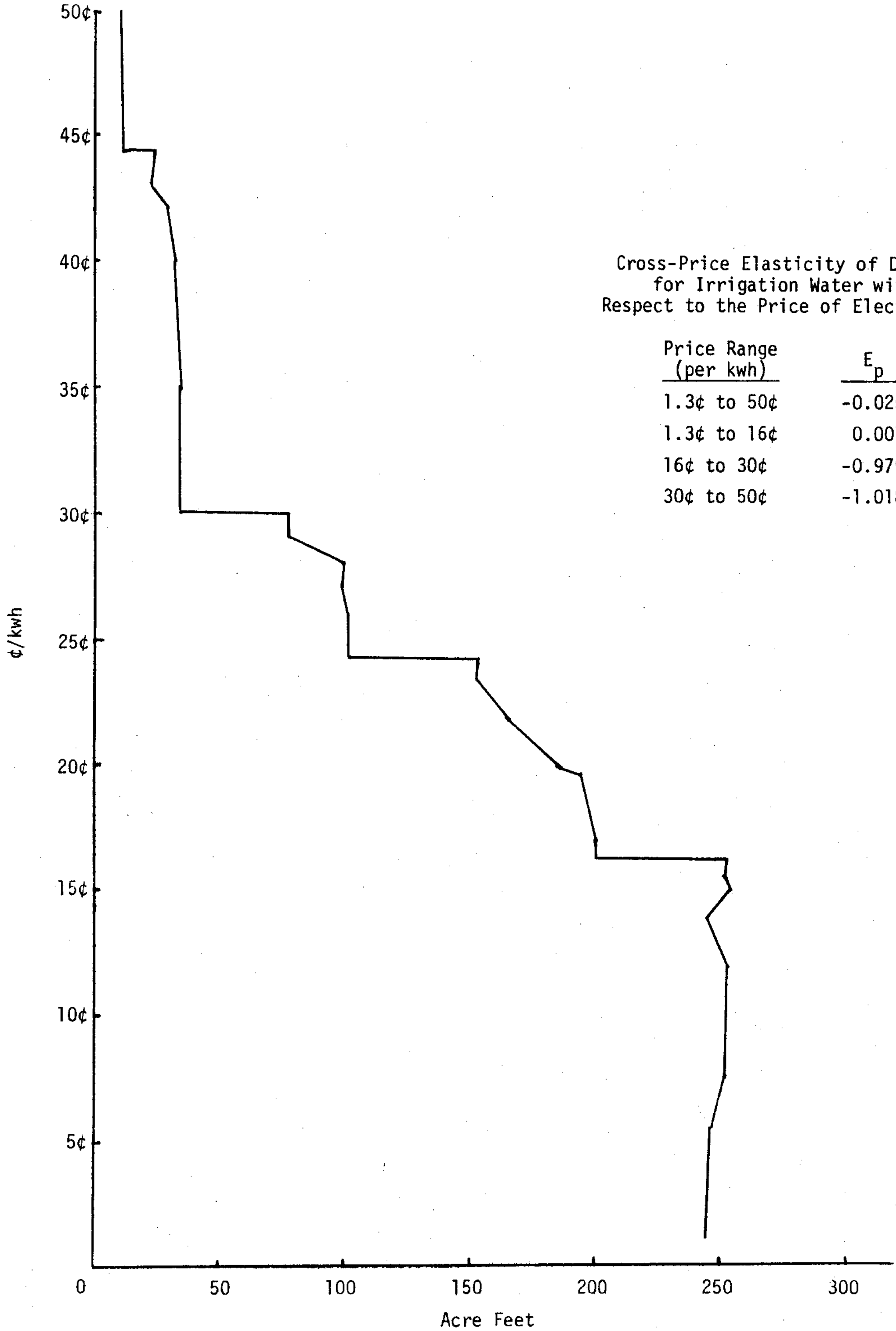
For any price of electricity, there are three costs of irrigation water due to the differing pumping requirements for the three irrigation systems. A conventional demand function using the cost of irrigation water is therefore difficult to construct. However, by varying the price of electricity and measuring the quantity of water demanded, a "cross" demand curve for irrigation water based on the price of electricity can be derived. Since the price of irrigation water varies directly with the price of electricity, the latter serves as a proxy for a price per acre foot of water.

It is not surprising that the cross demand curve (Figure 11) has the same stepped slope as the demand for electricity. Again the demand for irrigation water is extremely inelastic in the current price range of 1.3 to 16 cents. In fact, this portion of the demand curve for water actually has a small range which is somewhat backward bending and has a positive cross-price elasticity. This is due to the substitution of surface irrigation for sprinkler irrigation. Surface irrigation requires more water to be applied, but due to the low pressurization, less electricity is actually required. The demand curve does return to normal shape in the more elastic portion above 16 cents per kwh.

"Breakeven" Electricity Price

An examination of the "breakeven" prices for the crops included in the linear program does much to explain the stepped form of the demand functions. Breakeven prices of electricity show the level at which crops are no longer profitable and are eliminated from production.

Two breakeven prices were calculated. The short-run breakeven price shows the price of electricity which could be paid to irrigate a crop after the cost of all inputs except land, the irrigation system, management, and



Cross-Price Elasticity of Demand for Irrigation Water with Respect to the Price of Electricity

Price Range (per kwh)	E_p
1.3¢ to 50¢	-0.025
1.3¢ to 16¢	0.001
16¢ to 30¢	-0.979
30¢ to 50¢	-1.018

Figure 11. Estimated Cross Demand Per Well for Irrigation Water with Respect to the Price of Electricity Using 1977-81 Average Commodity Prices.

the user cost of water have been paid. It is not truly a short-run price because the fixed cost of farm machinery is included. However, it does show the level below which farmers who own their land will keep irrigating until they must replace their irrigation equipment. (Because this is an economic and not a financial analysis, farmers who are highly leveraged at high interest rates will not break even at the rates found in Table 2.) By including a payment for the irrigation system and management cost, a long-run breakeven price is found. Below that price farmers will keep irrigating as long as crop prices stay at average levels. (See Appendix 2 for further detail.)

Table 2 shows the highest short-run and long-run "breakeven" points for each of the crops analyzed. There are several interesting points here. First, gated pipe surface irrigation most commonly has the highest breakeven price. The electricity savings from not pressurizing the water apparently outweigh the higher water requirements of surface irrigation.

Table 2. Maximum "Breakeven" Electricity Rates Using 1977-81 Average Commodity Prices.

Crop	Irrigation System	Irrigation Level	Breakeven Rate ¢/kwh	
			Short Run[a]	Long Run[b]
Pinto Beans	GP[c]	One-third	63.1	23.4
	GP	Two-thirds	60.0	38.1
Sugar Beets	GP	Two-thirds	44.5	30.2
	GP	Five-sixths	43.9	31.7
Corn Grain	GP	Five-sixths	26.6	14.7
	GP	Full	25.1	14.8
Wheat	GP	Two-thirds	29.1	7.1
	LPCP[d]	Two-thirds	28.5	9.5
Grain Sorghum	GP	Two-thirds	13.7	----[e]
Alfalfa	GP	Full	12.5	6.5

[a]Returns to land, management, irrigation system, and water.
[b]Returns to land and water.
[c]Gated pipe surface irrigation.
[d]Low pressure center pivot.
[e]Unprofitable at any electricity rate.

shifts in relative crop prices. Such price effects would slow the transition to other crops. For instance, a large change from corn to irrigated wheat would tend to depress wheat prices while allowing the price of corn to rise. Another impediment in this case is that corn and wheat have overlapping growing seasons unless corn is cut for silage. This commonly means that another crop like pinto beans must be grown in a transition year. Given the low current price of beans, the transfer costs of a corn-to-wheat switch are increased.

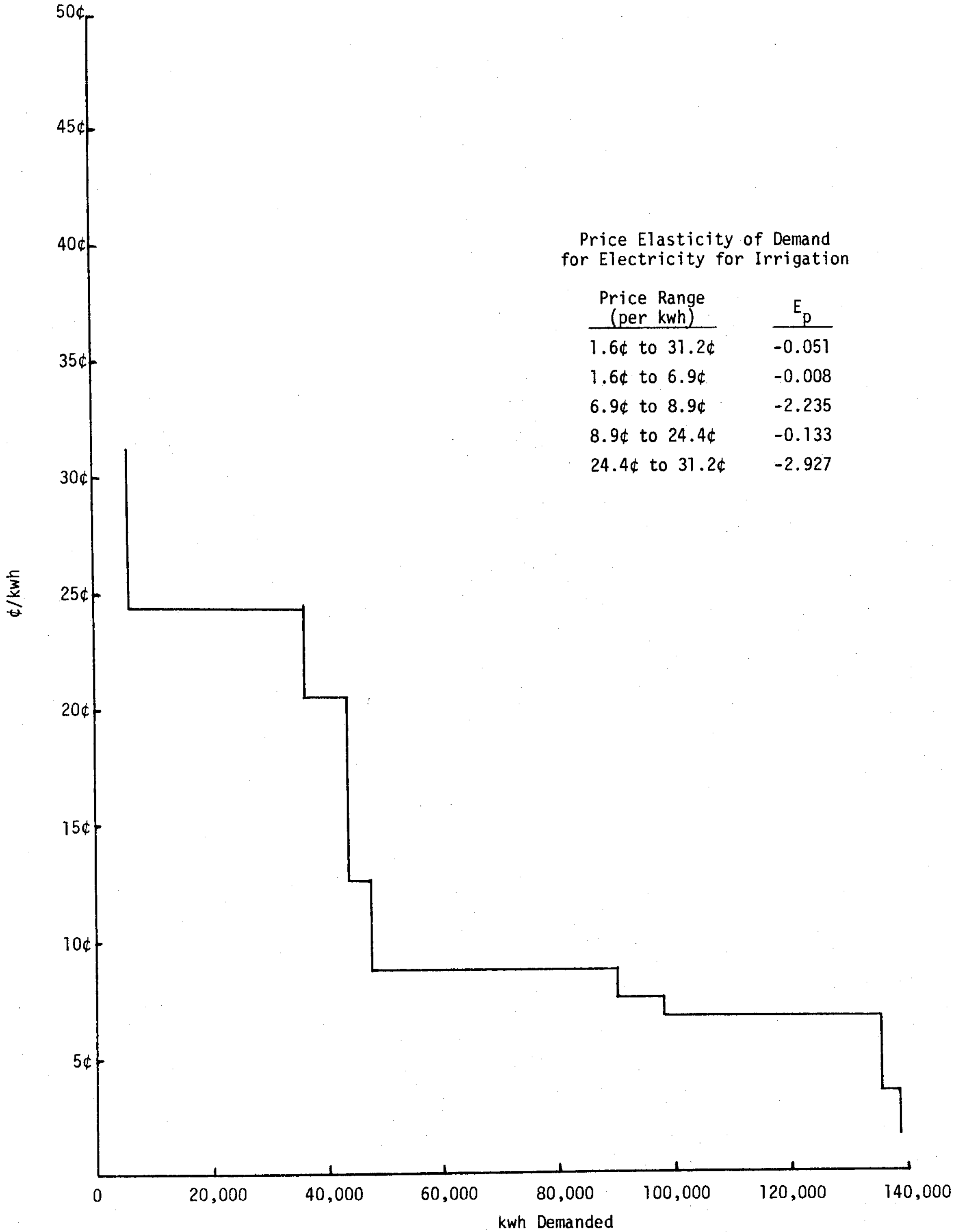
Sensitivity to Lower Crop Prices

The resource demand functions which are important in determining the effect of rate structures would be shifted by changed crop prices. Crop prices which existed in early 1982 were substantially below those which reflected the 1977-81 conditions (see Table 1). Therefore, the model was reformulated and solved with January 1982 commodity prices to test sensitivity to lower crop prices. The demand curves for electricity and water and breakeven prices were again estimated.

Electricity and Water Demand -- Low Prices

As might be expected, the entire demand curve for electricity shifted inward with lower crop prices; less power is purchased at any price level (see Figure 12). It is especially important to note that a very elastic portion of the demand curve, where irrigated corn shifts to irrigated wheat, now occurs in the 7 to 9 cent per kwh range. This range encompasses the present average cost of power, so that electricity consumption could fall sharply were single block pricing at long-run marginal cost adopted.

Figure 13 shows that very similar demand and electricity estimates hold for the demand for water with respect to the price of electricity.



Price Elasticity of Demand for Electricity for Irrigation

Price Range (per kwh)	E_p
1.6¢ to 31.2¢	-0.051
1.6¢ to 6.9¢	-0.008
6.9¢ to 8.9¢	-2.235
8.9¢ to 24.4¢	-0.133
24.4¢ to 31.2¢	-2.927

Figure 12. Estimated Demand Per Well for Electricity for Pump Irrigation in Eastern Colorado Using January 1982 Commodity Prices.

"Breakeven" Analysis -- Low Prices

The results of the breakeven analysis for 1982 prices are shown in Table 3. The breakeven rate for pinto beans fell so dramatically as to make other crops more profitable and eliminate beans from the crop mix. Sugar beets also leave before irrigated wheat with 1982 crop prices. While the short-run breakeven rate for corn is 13.8 cents per kwh, wheat becomes more profitable in the 7 to 9 cent per kwh range as shown in the demand curves. Wheat's short-run breakeven price of 23.1 cents per kwh explains the second elastic portion of the demand curve.

Table 3. Maximum "Breakeven" Electricity Rates Using January 1982 Commodity Prices.

Crop	Irrigation System	Irrigation Level	Breakeven Rate ¢/kwh Short Run[a]	Breakeven Rate ¢/kwh Long Run[b]
Pinto Beans	LPCP[c]	Full	7.7	---[e]
Sugar Beets	GP[d]	Full	16.3	7.3
Corn Grain	LPCP	Full	14.3	6.8
Wheat	LPCP	Two-thirds	24.3	5.7
Grain Sorghum	GP	Two-thirds	3.0	---
Alfalfa	GP	Full	9.6	3.8

[a]Returns to land, management, irrigation system, and water.
[b]Returns to land and water.
[c]Low pressure center pivot.
[d]Gated pipe surface irrigation.
[e]Unprofitable at any electricity rate.

The long-run breakeven rates show a dismal outlook if prices were to persist at or below the levels of early 1982. Current average power costs of 7.8 cents per kwh will force irrigated agriculture in eastern Colorado out of business in the long run if commodity prices do not improve.

Comparison to Previous Studies

The demand curves for electricity and irrigation water and corresponding elasticity estimates reported above generally fit quite well with past research. Adams, Lacewell, and Condra [1976] used a short run, parametric linear programming model to generate demand curves for irrigation water on the Texas High Plains with two levels of commodity prices. Their stepped demand functions were very similar to the ones reported here, exhibiting first inelastic and then very elastic portions. Bowen and Young [1982] used a linear programming model to demonstrate that the demand for irrigation water in Egypt is very inelastic in the current price range.

A short-run price elasticity of demand for electricity for pump irrigation in the Pacific Northwest was estimated at -0.3. Whittlesey, et al. [1981] found elasticities of -0.66, -0.66, and -1.08 for long-run price shifts of 0-100 percent, 100-200 percent, and 200-400 percent of current prices. The short-run and 0-100 percent long-run elasticity estimates are higher than those for Colorado. Perhaps the low current prices for electricity in the Pacific Northwest mean that low cost improvements in irrigation efficiencies are available when price increases.

Christensen, Morton, and Heady [1981, p. 32] examined price elasticities for irrigation surface and groundwater with a national model and found that "groundwater is more sensitive to its own price changes than is surface water." In contrast to surface water, groundwater arc price elasticities showed highly elastic areas where the elasticity exceeds 1.5, especially when groundwater prices were doubled and tripled. (Our demand curves for eastern Colorado that used 1982 crop prices showed a similar pattern.)

Ayer and Hoyt [1981] estimated the price elasticity for irrigation water on different soil textures and for specific crops in Arizona. Demand was generally inelastic, but in all cases the elasticity increased both as the price of water increased from $.50 to $5 per acre inch and as the crop price decreased. The same pattern was discovered by Kelly and Ayer [1982] for the price elasticity of demand for irrigation water in California for corn and cotton. Elasticity estimates were generally less than -0.3. Shumway [1973] found the long-run elasticity for irrigation water on the west side of the San Joaquin Valley rose from -0.48 at $4 per acre foot to -2.03 at $17 per acre foot.

Maddigan, Chern, and Rizy estimated short- and long-run price elasticities of electricity for irrigation of -1.081 and -2.123 through an econometric approach. These elasticities are perhaps higher than reported elsewhere, but they apply to the entire Central Region, which is characterized by numerous shallower wells in Nebraska, and by greater average rainfall than experienced in the Colorado portion of the Ogallala. Their econometric procedure computes an average demand across the observed range of prices, which smoothes out the steps which are characteristic of the linear programming approach.

RATE STRUCTURE ANALYSIS

This section individually examines several different aspects of rate structures and their effects on pump irrigation.

Experiment I. Hookup Versus Energy Charges

This first experiment investigates variation in the proportions of hookup versus energy charges, i.e., fixed versus variable costs to the farmer.

Different rate structures could be designed to yield the same utility revenue with many combinations of high hookup charge and low energy charges or low hookup charge and higher energy rate. Five such equivalent rate structures were modeled using the Kit Carson Electric Association's 1981 irrigation rate structure and their latest cost of service study [Tynes, 1981, 1982]. This rate structure utilized a hookup charge that varied with the horsepower rating of the motor. This was combined with a single block or constant energy charge per kwh of electricity consumed. The lowest energy charge of 1.826 cents per kwh represents the actual short-run marginal cost to Kit Carson Electric of providing an additional kilowatt to the average farmer.

The five rate structures modeled are listed in Table 4 along with the results. The structures varied from a hookup charge of $64.03 per horsepower and energy charge of 1.826 cents per kwh to a zero hookup charge and 7.8 cents per kwh. Thus, the marginal cost to a farmer of purchasing more power varied with each rate structure, providing gradations in the incentive to conserve. The rate structures each raise the same revenue for the utility <u>if</u> total irrigation sales of electricity remain constant. Figure 14 shows that the alternative rate structures are equal at the 107,000 kwh level of consumption which is somewhat below full irrigation of the standard crop mix.

Table 4. Experiment I: Forecasted Electricity Use, Water Use, and Net Returns to Fixed Assets (per well) for Varying Hookup and Energy Charge Combinations.

	Rate Structure ¢/kwh	Rate Structure $/HP	Acre Feet Pumped	Total kwh	Average ¢/kwh	Total Electricity Cost[a]	Farmer Net Returns[b]
1982 Electricity Prices							
A	1.826¢	$64.03	244	136,710	6.5¢	$ 8,899	$22,329
B	5.35	26	247	133,080	7.3	9,720	21,804
C	6.2	17	248	130,710	7.5	9,804	21,589
D	6.86	10	252	122,020	7.7	9,371	21,475
E	7.8	0	252	122,020	7.8	9,518	21,328
2 x 1982 Electricity Prices							
A	3.652	128.06	247	133,080	13.3	17,666	13,858
B	10.7	52	253	121,010	15.0	18,148	12,616
C	12.4	34	253	121,010	15.2	18,405	12,359
D	13.72	20	247	117,050	15.4	18,059	12,210
E	15.6	0	246	105,160	15.6	16,404	12,084
2.5 x 1982 Electricity Prices							
A	4.565	160.08	247	133,080	16.6	22,082	9,442
B	13.375	65	247	117,050	18.9	22,155	8,114
C	15.5	42.50	246	105,160	19.5	20,549	7,939
D	17.15	25	201	83,140	20.2	16,758	8,114
E	19.5	0	196	80,500	19.5	15,697	8,718
3 x 1982 Electricity Prices							
A	5.478	192.09	247	133,080	19.9	26,499	5,025
B	16.05	79	244	104,050	23.5	24,499	3,811
C	18.6	51	196	80,500	24.9	20,073	4,342
D	20.58	30	185	75,270	24.6	18,491	4,891
E	23.4	0	153	58,060	23.4	13,586	6,018
3.5 x 1982 Electricity Prices							
A	6.391	224.11	252	122,020	24.8	30,209	637
B	18.725	91	196	80,500	30.0	24,173	242
C	21.7	59.50	164	64,820	30.9	20,017	1,152
D	24.01	35	153	58,060	30.0	17,440	2,164
E	27.3	0	100	40,170	27.3	10,967	4,229
4 x 1982 Electricity Prices							
A	7.304	256.12	252	122,020	28.3	34,524	-3,679
B	21.4	104	164	64,820	37.4	24,272	-3,103
C	24.8	68	103	41,160	41.3	17,007	-1,553
D	27.44	40	100	40,170	36.5	15,023	173
E	31.2	0	35	15,050	31.2	4,694	3,241

[a]Total electricity cost to farmer equals utility revenue.
[b]Returns to land, management, irrigations sytem, and water.

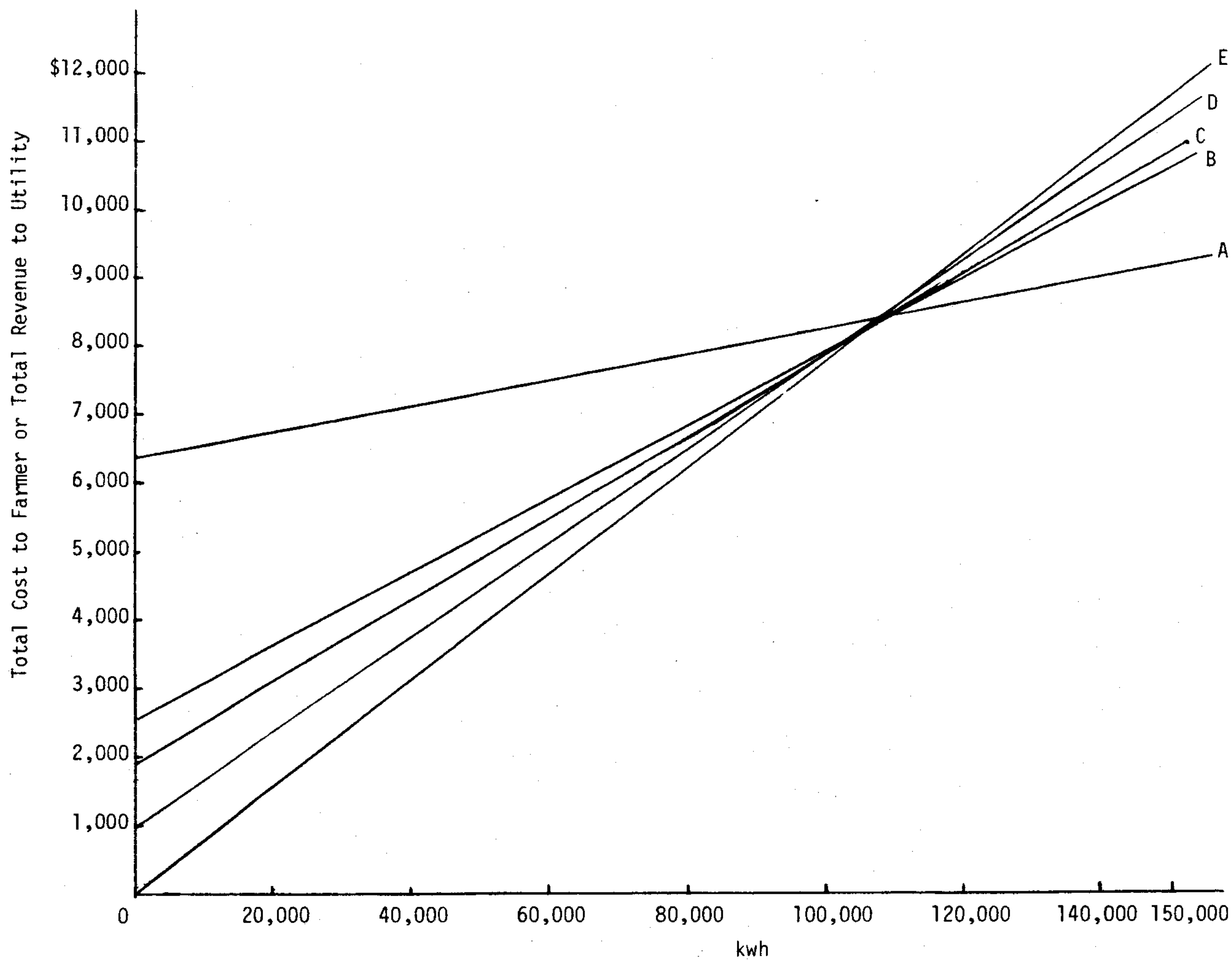


Figure 14. Alternative Single Block Rate Structures with Hookup Charge.

Each rate structure was incorporated into the linear programming model. The results appear in Table 4. At 1982 electricity prices, none of the rate structures deterred farmers from full irrigation. The decrease in power consumption from 136,710 to 122,020 kilowatts is solely due to a shift from high pressure to low pressure center pivot and gated pipe irrigation. The marginal costs to the farmers varied from 1.8 cents to 7.8 cents per kwh, all of which fall in an inelastic part of the demand curve.

Since the hookup and energy charge proportions did not substantially affect irrigation at current price levels, electricity rates were increased to determine if this aspect of rate structures would be important at higher rate levels. Electricity prices were therefore increased by factors of 2, 2.5, 3, 3.5, and 4.

Farmer purchases of power, as shown in the kwh and acre feet columns of Table 4, were affected more and more dramatically as electricity prices increased. This was because the range of marginal costs became larger with each price increase. Note that in every case rate structure A, with the lowest marginal cost, allowed full irrigation. The effect on crop mix of change to a zero hookup and higher energy charge rate structure became more substantial with each price level increase. Doubling price to 15.6 cents per kwh caused lower irrigation levels on some corn. The 2.5 and 3 times 1982 price levels brought in irrigated wheat. The 3.5 factor, 27.3 cents, level eliminated corn from the crop mix. These changes are all related to the breakeven prices described earlier.

Utility revenue was more affected by the hookup charge level than farm income. Utility revenue, listed as total cost in Table 4, is fairly constant at 1982 and doubled price levels. However, as the higher marginal cost rate structures begin to induce conservation, utility revenues fall accordingly.

The higher the marginal cost and the lower the hookup charge, the more a farmer can reduce power bills by conserving. Thus, conservation incentives in this rate form come at the expense of utility revenue stability. This point can be illustrated by referring back to Figure 14 and observing that revenue drops much more quickly with rate structure E than with A. With no hookup charge and a single block rate structure, utilities are vulnerable to revenue shortfalls from conservation efforts.

The alternative rate structures have a less consistent effect on farm net income. Income falls slightly as marginal cost increases in the first three price levels. However, at the prices 3, 3.5, and 4 times 1982 levels, net income to farmers rises with marginal cost. An explanation is that the low marginal cost allows more irrigation, but the high hookup charge takes away nearly all consumer surplus. High marginal costs cause less irrigation, but the low hookup charge allows some consumer surplus to be preserved.

The net farm income in Table 4 needs to be compared to the income that could be gained from dryland farming on the equivalent acreage, namely $2,530. In the short run, farmers will switch to dryland when net income falls below this level. Thus, at 3.5 and 4 times 1982 prices, farmers would only irrigate with rate structure E and then only on the higher valued crops.

In the long run farmers must also have sufficient net income to pay the $6,530 annual cost of irrigation system reinvestment. With this additional expense, irrigation would cease in the long run with any rate structure except A at the 2.5 times 1982 price level. One caveat to remember is that this model represents aggregate irrigation of a crop mix. Irrigation of higher valued crops such as sugar beets and pinto beans would continue after the bulk of irrigated lands have converted back to dryland, so long as the prices of these crops met the average of the 1977-81 period.

Experiment II: Alternative Rate Structures

In this section the effect of alternative rate structures on electricity demand, water use, and farm income is tested by the model. This experiment also serves to emphasize the importance of marginal cost as the rational decision-making criterion for power purchases. The demand curve for electricity was estimated earlier. By comparing the shape of demand with the marginal cost curves of various rate structures, power consumption and utility revenues can be estimated. Since electricity demand is quite inelastic at average commodity prices, a broad range of alternative rate structures should yield similar results.

The concept of a fixed hookup charge is not used here; all revenues are considered to be collected by variable kwh charges. These rate structures can, however, serve the same purpose as hookup charges by having some of the first rate blocks exceed the utility's short-run marginal cost. This takes revenue from the consumer surplus to pay fixed costs.

Seven alternative rate structures were designed to provide approximately the same revenue to the utility per well, that is, $9,500. Average commodity prices were assumed in constructing the rate, though January 1982 commodity prices were used in a subsequent test. The rate structures were all expected to result in full irrigation despite their quite different forms.

The seven alternatives are listed in Table 5. Alternative 1 is reminiscent of that currently used by Y-W Electric Association. The second alternative uses an even wider range of prices with more blocks. Its lowest block of 2 cents per kwh probably represents the low end of the range of feasible prices as that charge approaches the short-run marginal cost of most REAs. Alternative 3 is similar to the first rate structure but shows a smaller range of prices. The fourth and fifth alternatives are the simplest form of declining blocks.

Alternative 4 has a more precipitous drop in price and is similar to the K.C. Electric Association rate structure. The sixth alternative is an example of increasing block rates, while the last alternative demonstrates a single block form.

Table 5. Alternative Rate Structures for Experiment II.

Type	Block Limits	Charge per KWH
#1 Declining Blocks	First 2,000 KWH	25¢
	Next 25,000 KWH	13¢
	Next 25,000 KWH	10¢
	Additional	4¢
#2 Declining Blocks	First 10,000 KWH	30¢
	Next 10,000 KWH	20¢
	Next 10,000 KWH	15¢
	Next 10,000 KWH	10¢
	Additional	2¢
#3 Declining Blocks	First 25,000 KWH	12¢
	Next 25,000 KWH	10¢
	Next 25,000 KWH	8¢
	Additional	4¢
#4 Declining Blocks	First 50,000 KWH	16¢
	Additional	2¢
#5 Declining Blocks	First 50,000 KWH	9¢
	Additional	6¢
#6 Increasing Blocks	First 25,000 KWH	6¢
	Next 25,000 KWH	7¢
	Next 25,000 KWH	8¢
	Next 25,000 KWH	9¢
	Additional	10¢
#7 Single Block	All KWH	7.8¢

Placing these seven alternative rate structures into the LP model produced the results displayed in Table 6. When average commodity prices were used, utility revenue or energy costs differed by less than 3 percent while net farm revenues varied by less than 5 percent. All the rate structures allowed full irrigation, though alternatives 6 and 7 used more surface irrigation to save energy. The most striking result here is the lack of effect that the choice of rate structure makes at average commodity prices.

Table 6. Experiment II: Forecasted Electricity Use, Water Use, and Net Returns to Fixed Assets for Alternative Rate Structures (per well).

Rate Structure	Total Electricity Cost[a]	Total KWH	Average ¢/KWH	Acre Feet Pumped	Farmer Net Returns[b]
Average Commodity Prices					
1	$9,243	133,080	6.9¢	247	$22,281
2	9,434	136,710	6.9	244	22,219
3	9,573	133,080	7.2	247	21,701
4	9,734	136,710	7.1	244	21,919
5	9,343	130,720	7.1	248	22,051
6	9,601	121,010	7.9	253	21,163
7	9,518	122,020	7.8	252	21,328
January 1982 Commodity Prices					
1	$9,347	135,670	6.9¢	251	$9,899
2	9,486	139,300	6.8	248	9,889
3	9,677	135,670	7.1	251	9,569
4	9,786	139,300	7.0	248	9,589
5	9,640	135,670	7.1	251	9,605
6	5,250	75,000	7.0	159	9,562
7	7,058	90,490	7.8	179	9,090

[a]Total electricity cost to farmer equals utility revenue.
[b]Returns to land, management, irrigation system, and water.

However, Table 6 shows that low commodity prices, such as those of January 1982, can make rate structure important. The five declining block alternatives still provided nearly identical results. But with the increasing and single block alternatives and their higher effective marginal costs, farmers would be expected to reduce irrigation in response to low crop prices. This caused sharply lower utility revenues, though net farm income fell only slightly. The conversion of corn to wheat makes sense in terms of resource conservation, though it reduces utility revenues. The reduction in feed grain production would help crop price recovery while holding scarce Ogallala aquifer water for later, possibly more valuable, uses.

Experiment III: Seasonal Rate Structures

The last experiment with the linear programming model incorporates seasonal rate differentials. The wholesale supplier of power, Tri-State Generation and Transmission, currently makes two different demand charges to the Rural Electric Associations (REAs) in eastern Colorado. It charges \$10.99 for each kilowatt of peak demand. A further ratchet charge of \$5.47 per kilowatt is assessed for the amount by which the summer-winter demand difference exceeds the 1974 difference. A kwh used in the peak month costs far more than the 1.561¢ energy charge that Tri-State also assesses. Thus, REAs have a strong incentive to reduce the summer peak energy demand, which is mostly due to irrigation.

Load Management

One way to encourage a lowering of the peak and to spread out energy demands is to use a load management rate structure. This allows the power utility to cut off an irrigation pump one or possibly two days a week. Stopping irrigation on one-seventh of the wells each day should lower the peak demand. Some REAs, such as Y.W. Electric and Highline Electric, give rate discounts for farmers who sign up for this program. Given existing pump capacity, no yield reductions are expected from this interrupted service. Since REAs are non-profit cooperatives and any savings should be reflected in lower rates, a well publicized voluntary program might be effective. K.C. Electric claims to have just that. However, a voluntary program distributes the cost savings to all consumers, not specifically to those who endure the inconvenience. This reduces the incentive to participate in a voluntary program. Due to the lack of costs associated with enrollment, we did not assess load management discount rates with the computer model.

Seasonal Rates with 1977-81 Prices: Experiment III-A

Instead, another peak load management option was examined. Seasonal rates can move energy demands away from the peak period by offering lower rates for non-peak use. Public utility rate theory imples that if capacity must be built for part-time use to meet peak demands, then the peak demand price should be the long-run marginal cost which includes incremental capacity costs while the off-peak price should be only short-run marginal cost or operating costs. However, this policy would result in high peak prices and very low off-peak prices. The large difference is very probably politically infeasible [Seagraves and Easter, 1982], and we considered a less stringent, more pragmatic, tack. To the extent that irrigation in the peak period causes higher cost, such as demand and ratchet charges to the REA, non-peak discounts promote more efficient resource use and should be encouraged.

In eastern Colorado peak usage occurs during June, July, and August. The model was therefore adjusted to charge energy use the full rate during these months, while giving a discount to pumping in April, May, and September. Since wheat can be irrigated in these months, this seasonal rate structure provides a cost advantage for this crop.

Discounts of 10, 20, and 30 percent were given to off-peak irrigation. In addition, five of the alternative rate structures used in the previous section were retained here (see Table 5). This provides a variety of marginal energy costs to the farmer both before and after discounting.

The model was first run using the average crop prices (Experiment III-A). However, the seasonal rate caused no change in the crop mix even with a 30 percent discount. At average commodity prices and up to 30 percent discount, the profit advantage of corn is apparently too great to be overcome.

Seasonal Rates with 1982 Prices: Experiment III-B

The model was rerun with January 1982 crop prices. The results appear in Table 7. Here relative crop prices are such that wheat is grown under the increasing and single block rates (Alternatives 6 and 7) even without a seasonal discount. This continues with the 10 and 20 percent discounts, but at 30 percent, with declining block rate (Alternative 5), a conversion to wheat also occurs. When wheat is grown, energy use and utility revenues drop sharply. However, net farm income remains roughly the same or is even higher with irrigated wheat than with corn. This shows that at current farm prices, seasonal rate structures could conserve both water and peak period energy, while maintaining the economic viability of farming in the region. Significant reductions in supplier revenues would be associated with such a policy.

To summarize, relative crop prices seem to generally outweigh the cost advantages given by seasonal rate structures. However, there are combinations of commodity prices and discount rates where the encouragement of more efficient resource use will cause a conversion to crops with more off-peak water and energy demands.

An important option which this project was unable to explore is that seasonal rates could cause the promotion of new irrigation timings for conventional crops. Colorado State University irrigation specialist Don Miles has proposed using large early irrigations to fill the soil profile with moisture within the potential root zone. This approach could allow later irrigations to be foregone, reducing peak summer demands [Miles, 1977].

Irrigation load management with interruptable service and seasonal rates are compatible. Load management should be encouraged either through a strong voluntary program or with rate discounts. Off-peak energy rates

Table 7. Experiment III-B: Forecasted Electricity Use, Water Use, and Net Returns to Fixed Resources (per well) for Seasonal Rate Structure with January 1982 Crop Prices.

Rate Structure	Total Energy Cost[a]	Total kwh	Average ¢/kwh	Acre Feet Pumped	Farmer Net Returns[b]
No Discount					
3	$9,677	135,670	7.1¢	251	$ 9,569
4	9,786	139,300	7.0	248	9,589
5	9,640	135,670	7.1	251	9,605
6	5,250	75,000	7.0	159	9,562
7	7,058	90,490	7.8	179	9,090
10% Discount					
3	9,592	135,670	7.0	251	9,654
4	9,742	139,300	7.0	248	9,633
5	9,513	135,670	7.0	251	9,733
6	5,250	78,830	6.7	156	9,864
7	6,787	90,490	7.5	179	9,362
20% Discount					
3	9,507	135,670	7.0	251	9,739
4	9,698	139,300	7.0	248	9,677
5	9,385	135,670	6.9	251	9,861
6	5,250	82,440	6.4	163	10,185
7	6,515	90,490	7.2	179	9,634
30% Discount					
3	9,422	135,670	6.9	251	9,824
4	9,654	139,300	6.9	248	9,721
5	3,360	51,300	6.5	99	9,312
6	5,250	85,860	6.1	170	10,488
7	6,244	90,490	6.9	179	9,905

[a]Total electricity cost to farmer equals utility revenue.
[b]Returns to land, management, irrigation system, and water.

should also be discounted to the extent the marginal cost to the utility of off-peak energy is lower. Even if the seasonal rate does not cause any change in farm resource use at first, it may be important to have seasonal rates in place to provide the incentive for more efficient resource allocation when economic conditions warrant.

EVALUATION OF EXISTING RATE STRUCTURES

Given the results of this research and the economic principles applicable to rate design, an evaluation can now be made of the current electricity rate structures employed by the REAs of eastern Colorado and their wholesale suppliers. This evaluation contains some subjective judgements reflecting the authors' views. In particular, we advocate a rate structure based on long run marginal cost of electricity supply. The current understanding of LRMC pricing focuses on the amount of future resources used or saved by user decisions (Munasinghe and Warford, 1982). This contrasts with the traditional approach, which is concerned with historical or sunk cost recovery. Prices that reflect the true economic cost of supplying the users needs permits supply and demand to be matched efficiently.

Long run marginal cost pricing satisfies the equity principle in that costs are charged to users according to the burden they impose on the system. (The equity or fairness concept calling for provision of minimum service levels to those who cannot afford fuel costs class not appear to be relevant in the present case of irrigated agriculture.)

Pricing according to the LRML criteria will also raise sufficient revenue to meet the system's financial requirements, though some connection charges may be needed in the case of economies of scale.

Finally, a forward looking LRMC rate scheme - one based on future rather than historical costs - would serve as an inhibatory force on excess water withdrawals and thereby work toward preserving the limited water supply.

Wholesale Rates

Some comments on the wholesale rates are appropriate first since they are a major influence and constraint in the design of REA rates (see Table 8).

Table 8. Wholesale and Retail Rate Structures for Electricity, Colorado High Plains, 1983

WHOLESALE RATES		
Tri-State Generation and Transmission Association		
Energy Charge	All kwh	$ 0.01561/kwh
Demand Charge		10.99/kw
Ratchet Charge for Peak Demand		5.47/kw ratchet demand
Colorado Ute Electric Association		
Energy Charge	All kwh	$ 0.03884/kwh
RETAIL RATES		
Y-W Electric Association		
Summer Irrigation Rate		
Energy Charge	First 1000 kwh	$ 0.254/kwh
	Next 250 kwh/hp	0.125/kwh
	Next 250 kwh/hp	0.096/kwh
	Additional	0.042/kwh
Minimum Charge	First 50 hp	$18.50/hp
	Additional	13.00/hp
Load Management Irrigation Rate		
Energy Charge	First 1000 kwh	$ 0.254/kwh
	Next 210 kwh/hp	0.125/kwh
	Next 210 kwh/hp	0.096/kwh
	Additional	0.042/kwh
Minimum Charge	First 50 hp	$18.50/hp
	Additional	13.00/hp
Winter Irrigation Rate (Sept. 10-June 15)		
Energy Charge	First 1000 kwh	$ 0.254/kwh
	Next 185 kwh/hp	0.125/kwh
	Next 185 kwh/hp	0.096/kwh
	Additional	0.042/kwh
Minimum Charge	First 50 hp	$14.00/hp
	Additional	10.00/hp
K.C. Electric Association		
Summer Irrigation Rate		
Energy Charge	First 250 kwh/hp	$ 0.1626/kwh
	Next 250 kwh/hp	0.13/kwh
	Additional	0.01826/kwh
Old Summer Irrigation Rate		
Energy Charge	All kwh	$ 0.058/kwh
Hookup Charge	All hp	$26.00/hp
Highline Electric Association		
Summer Irrigation Rates		
Energy Charge	First 300 kwh/hp	$ 0.124/kwh
	Next 300 kwh/hp	0.066/kwh
	Additional	0.0474/kwh
Minimum Charge	All hp	$25.00/hp
Load Management Discounts		
Subject to control on pre-determined day/week		7%
Subject to control during all peak periods		14%
Winter Irrigation Rate (Oct. 15-April 15)		
Energy Charge	All kwh	$ 0.0623/kwh
Southeast Colorado Power		
Irrigation Rates		
Energy Charge	First 200 kwh/hp	$ 0.086578/kwh
Additional in summer		0.080778/kwh
Additional in winter (Oct. 1-April 30)		0.064378/kwh
Minimum Charge	All hp	$15.00/hp

Tri-State Generation and Trasmission charges a relatively low rate of 1.561 cents per kwh for energy while assessing substantial demand and peak demand charges. A peak demand charge is based on the cost of providing capacity for peak use. While the energy charge may reflect short-run marginal costs and allocate supplies efficiently in the near term, it will tend to encourage premature expansion as system capacity is approached. A low energy charge at the wholesale level allows REAs to have similarly low final blocks in their rate structures. This structure does not effectively discourage consumption, and from a state policy viewpoint it neglects the user cost of Ogallala water. It is the authors' belief that charging for the short-run marginal cost does not provide an accurate signal in the market, because it does not contain the full opportunity cost of providing capacity. This opportunity cost is the average cost of adding to or replacing capacity in the present; it is not average historical costs incurred in the past. (See Saunders, Warford, and Mann, 1977 for further detail.) Tri-State's pricing policy is perhaps appropriate, however, given their current excess capacity.

Colorado Ute Electric is at the other extreme of wholesale pricing. As our research confirmed, single block charge provides considerable encouragement to conserve energy. However, Colorado Ute might consider combining its average cost pricing with some sort of peak demand charge in order to reflect the opportunity cost of expanding system capacity.

Retail Rates

At the retail level, Table 9 compares the charges each REA would make to the owner of a 100-horsepower pump in 1982 under different levels of consumption and with different rate categories. Strict comparisons are inappropriate due to the different cost structures of each REA. However, it is instructive to examine the discounts given by load management and winter rates. This table also shows that the rate structures with the higher marginal

Table 9. REA Irrigation Charges Under Varying Rate Structures and Levels of Consumption[a/]

		Number of Kilowatts Consumed in Season				
REA	Rate	40,000	60,000	80,000	100,000	120,000
Y-W	Summer	$4,723	$6,157	$6,997	$7,837	$8,677
K.C.	Summer	6,015	7,498	7,863	8,228	8,593
K.C.	Old Summer	4,920	6,080	7,240	8,400	9,560
Highline	Summer	4,380	5,700	6,648	7,596	8,544
S.E. Colorado	Summer	3,347	4,963	6,578	8,194	9,809
Y-W	Load Management	4,607	5,609	6,449	7,289	8,129
Highline	Load Management 7%	4,073	5,301	6,183	7,064	7,946
Highline	Load Management 14%	3,767	4,902	5,717	6,533	7,348
Y-W	Winter	4,427	5,267	6,107	6,947	7,787
Highline	Winter	2,492	3,738	4,984	6,230	7,476
S.E. Colorado	Winter	3,019	4,307	5,594	6,882	8,169

[a/] Assuming 100 hp pump motor.

rates have a much greater variation in total cost between small and large levels of purchase. For example, compare the Highline and K.C. summer rates. Both make nearly the same charge at the 120,000 kwh level, but Highline gives a much larger saving for reducing consumption.

The rate structure that charges high marginal cost gives farmers more flexibility in irrigation decisions by not discriminating against low irrigation levels. In constrast, power suppliers may fear this variation in revenue and its effect on debt repayment capacity. Therein lies the crux of the problem. Incentives for conservation and more efficient resource use come at the expense of greater variability and large potential reductions in utility revenue. Revenue problems are further exacerbated by the requirements that the cooperatives REAs refund excess revenues each year. This eliminates the possibility of averaging surpluses and shortfalls over the years.

The effect of a minimum charge is to make the rate structure up to the minimum charge nearly irrelevant. Since the minimum charge must be paid if any power is to be purchased, the kilowatt hours allowed by the minimum payment have a marginal cost of zero. For example, Y-W's charge of $1,575 for 100 horsepower attaches a zero marginal cost to the first 11,568 kwh. This causes inefficient resource allocation for anyone who would otherwise use less than that amount. While this may be unlikely we consider a minimum charge to be inessential to an effective rate structure. Less ambiguous charging techniques are either a hookup charge or a higher than marginal cost initial rate block that most irrigators will exceed.

For Y-W Electric the minimum charge renders the initial block of 1000 kwh an unnecessary complication. An improvement would be to drop that block and raise the level of the next block slightly. The minimum charge could probably be dropped at little risk since the vast majority of irrigators will exceed that level of consumption. Y-W's load management rate is made by shortening the length of the early, more expensive, blocks. This means that the discount is all obtained once an irrigator progresses past 50,000 kwh in the cheapest block. Yet the benefits to the utility of load management may continue beyond this level. This feature might be changed so that the farmer is rewarded at any level of consumption. Highline Electric's percentage discount is an example.

The same lack of proportional savings applies to Y-W's winter rates. Shortening the early block of a rate structure is also more difficult to understand than a percentage discount on the rate. Farmers may not see the savings or the connection between peak and off-season billing. Since off-season electricity use actually costs the utility less, this rate should be lower. Y-W does not give as great a proportional discount as either Highline or S.E. Colorado Power. The Y-W winter rate does, however, define a short enough peak season as to make the off-season rate practical for use.

In 1982 K.C. Electric Association tried a declining block rate structure rather than its historical use of a single block with hookup charge. The lack of a minimum charge with the declining blocks is unique among the REAs examined. This change in rate form significantly lowers the incentive to conserve electricity and, indirectly, water. The final block rate is a low 1.826 cents per kwh. Farmers have little reason to reduce energy or water use once the final block has been reached at 50,000 kwh. Its old rate structure had a hookup charge to provide some secure revenue for fixed costs, yet kept the energy charge at a level high enough to provide significant savings to conservation efforts.

Table 8 shows that Highline Electric uses a declining block rate structure with a final block of 4.74 cents per kwh. Its rather large minimum charge may impinge on the irrigation choices of some farmers, especially since its northeastern Colorado service area contains more shallow wells.

The load management discounts Highline offers are unambiguous and easy to administer. Similarly, the Highline single block winter rate is laudable, but the long peak season makes use of the winter rate difficult.

A final and interesting case is that of Southeast Colorado Power. Its rate structure, at first glance, appears to be the best in terms of economic efficiency. The use of two blocks, the first slightly higher to cover administrative costs, yet both probably near the level of long-run marginal cost, provide an accurate signal to consumers of the cost of additional consumption. The second block varies with the season, smoothly integrating differential rates into one rate structure. The only problem is that the summer season might be shortened to make the winter rates more effective.

It is ironic that the S.E. Colorado Power rate structure provides the most encouragement to energy conservation. This REA is in the unfortunate situation of having high fixed costs from recent distribution system investments. With declining water tables, irrigation pumping near the economic margin, and a wholesale rate that has no peak charge added to the picture, S.E. Colorado Power faces the quandary of having a revenue shortfall lead to a rate increase which in turn causes even less irrigation and still lower revenues. S.E. Colorado Power might be one of the rare cases where declining blocks make sense. It cannot afford to set high marginal prices because they have been all too effective in getting farmers to reduce irrigation. When the base load is reduced, the high fixed costs can only force another increase in rates. So a declining block irrigation rate to maintain a stable level of consumption might be appropriate here until the debt load has been reduced. Of course, the risk is an earlier depletion of available groundwater.

SUMMARY AND CONCLUSIONS

Summary

Economic theory reveals that in order to maximize profits from crop production, farmers must match the price of an additional unit of electricity with the marginal value product of the use of that energy in irrigation. The important price is that of the last unit consumed. Assessing agricultural demand for energy provides a perception of the flexibility available in designing rates. Also of importance is the cost of producing electricity. The marginal price applicable to farmers should reflect the cost of supplying the energy if resource use is to be efficient.

A linear programming model was used in this study to estimate the demand for electricity and pump irrigation water and to analyze the effects of various rate structures on farm resource allocation and income. The model was formulated to derive the most profitable operation of a typical irrigation well and quarter-section in eastern Colorado. Seventy-four crop growing options were available including six crops, three to four levels of irrigation, and three irrigation technologies. From the results of this research several points can be made in summary.

1. Crop prices are more important than electricity rate structures in determining the feasibility of irrigation and the most profitable crop mix. Electricity for pumping irrigation water is but one of many inputs needed for crop production. If a crop is much more profitable than the next best alternative, then it will likely remain in production no matter what the rate structure. However, when crop prices fall, lowering profit margins as well, rate structure can be a significant factor in farm management decisions.

2. With five-year average commodity prices, the demand curves estimated by the model for both electricity and water are highly inelastic within the

relevant electricity price range. However, demand approaches unitary elasticity as corn shifts to irrigated wheat at electricity prices greater than 15 cents per kwh. Short-run breakeven electricity rates range from over 60 cents per kwh for pinto beans to 12.5 cents per kwh for alfalfa.

3. When January 1982 crop prices apply, price elasticities exceeding 2.0 occur in the 7 to 9 cent per kwh range. Farmers can be expected to react to electricity prices in this range by growing irrigated wheat to conserve energy and water. Careful planning is therefore required by the utilities to accomodate declines in electricity usage. If crop prices return to pre-PIK program levels, this portion of the analysis will have the most relevance to utilities and regulatory agencies.

4. Varying the proportions between hookup and energy charges has little effect on irrigation under average crop prices until electricity prices are more than double the 1982 average cost. Then higher energy charges and lower hookup charges encourage conservation. Farm income remains stable with conversion to less energy intensive crops, but this comes at the expense of utility revenues. High hookup charges stablize utility revenue but can encourage excessive use of electricity and water.

5. As might be expected, given the inelastic demand, alternative rate structures do not affect farm irrigation decisions if five-year average crop prices prevail. A variety of declining block, increasing block, and single block rate structures with a broad range of marginal prices all yielded predictions of full irrigation and approximately the same revenues to both farmer and utility. Under the 1982 crop price assumption, the single block and increasing block rate structures did cause reduced irrigation.

6. This study found that the effects of seasonal rate structures in encouraging off-peak irrigation were outweighed by relative crop prices.

However, possible innovations in irrigation scheduling were not analyzed in this report. Seasonal rate structures are recommended to the extent that off-peak power is less costly. They provide an incentive to farmers in favor of spreading out their demand for electricity.

7. Although the model was run in this study for the area around Burlington, Colorado, the results can be extended, with some modification, to other irrigated areas of the state. In northeastern Colorado and especially the alluvial wells of the South Platte Valley, the demand for electricity and water will be higher than those found here for any given commodity price scenario. This is due to lower pump lifts, and it means that northeastern Colorado farms will tend to be less sensitive to rate structure changes. On the other hand, the demand curves of southeastern Colorado should lie inside those of the Burlington area due to deeper wells and higher evapotranspiration rates. This should lower crop profit margins and make southeastern Colorado irrigation more sensitive to electricity rates.

Limitations of the Study

In interpreting the results of this study several caveats need to be repeated. One important consideration is that this report has relied exclusively on partial analysis. That is to say that only one variable in the model has been manipulated while all others were held constant. In reality, all market prices, and thus farmer decisions, are interconnected. For instance, low commodity prices would eventually cause the use of less fertilizer and other inputs. Another possibility is that substantial shifts in the crop mix could reverberate through the market to cause crop price changes. A major shift from corn to wheat production, for example, would put downward pressure on the price of wheat while allowing corn prices to rise.

The model employed in the study also allowed some shifting between irrigation systems, which would only happen with considerable cost. While this cost was not incorporated into the model, the results are not believed to be substantially altered by this factor. Major shifts in irrigation systems were constrained in the model. Additionally, the most common switch was from high pressure to low pressure center pivot, which only requires different spray nozzles, and is not expensive.

Finally, these results must be used with care because the response would likely change with different economic conditions or in another geographic area. However, this type of linear programming model could be a valuable tool for utility planners to test ideas for specific rate structures. Once budgets are prepared for each crop enterprise, the model can be easily updated to current prices and adapted to a wide variety of rate structures or situations.

Conclusion

Rate structures which charge higher marginal prices for electricity provide farmers with more flexibility in their irrigation decisions in the form of greater rewards for reduced irrigation. In contrast, power suppliers must be concerned about this potential variation in revenue and its effect on their debt repayment capacity. Therein lies the crux of the problem facing rate policy-makers. The criteria of efficiency and revenue requirements conflict. If utility revenues decline along with energy use, utilities may have to increase their charges per kwh in order to meet fixed costs. The farmers' "reward" for conserving energy could thus be a rate increase. This vicious circle is a particular dilemma to those utilities who have recently increased capacity and updated distribution systems at considerable cost in mistaken anticipation of a continued expansion of irrigation.

Revenue problems are further exacerbated by the federal regulation requiring that Rural Electric Associations (REAs) refund excess revenues each year. The occasional shortfalls that tend to occur naturally from variations in the weather cannot be absorbed from periods of surplus. Permission for the utilities to retain a reserve fund to smooth out revenue fluctuations might reduce their need to collect a large part of their revenues by fixed charges.

In general, REAs in eastern Colorado continue to use declining block rate structures in a time when pump irrigation no longer needs to be encouraged. Declining block rates and large hookup charges provide revenue stability for the utility by monetizing some of the consumers' surplus on inframarginal units of electricity. This revenue stability comes at the expense of minimizing the incentive to conserve and use resources efficiently. A scenario of continued full irrigation of traditional crops with conventional technology, leading to an earlier depletion of the Ogallala aquifer, is thus promoted.

One way to prolong irrigation in eastern Colorado is to implement electricity rates which reflect both the higher incremental costs of energy and the increasing scarcity of water in the declining Ogallala aquifer. An increasing block rate structure which ends at long-run marginal cost deserves serious consideration in those portions of the region which are expected to experience growing electricity demand. (Randall, 1981:12; Hanke, 1972:292-295; Turvey, 1971:73.) The lower first block could be used to avoid a revenue surplus and to offer a minimum amount of irrigation at a nominal price. The final block's price would contain all costs of expanding capacity and thus provide an accurate market signal to farmers of the cost of additional consumption.

If increasing blocks are not used, then allowing REAs to average irrigation revenue over several years would ameliorate the conflict between allocative efficiency and revenue requirements in rate structure design. This would lower the need for hookup charges and high initial rate blocks and allow the use of single block or very gradually declining block rates.

In the interest of meeting the goal of rate stability, a change to inverted blocks or a single block may require one or more temporary incremental moves towards higher marginal prices for electricity. A well publicized and orderly rate structure shift over several years would minimize effects on past investments.

Unfortunately, little or no work seems to have been done on optimal pricing under decreasing demand. The established literature on public utility pricing tends to deal with the more conventional case of growing demand for the product (Saunders, Warford, and Mann, 1977; Hanke, 1972; Munasinghe and Warford, 1982). Deepening wells, impending aquifer depletion, and increasing power costs are reducing the profitability of irrigation from the Ogallala aquifer. In fact, irrigated acreage in eastern Colorado is forecasted to decline by 40 percent by the year 2020 (Young, et al., 1982). Yet the fixed costs of REAs must still be recovered if they are to avoid default on debt. Discount pricing through declining blocks or two-parts tariffs like hookup charges can encourage continued full irrigation and thus, debt recovery at the cost of hastier aquifer depletion. An alternative more in tune with regional economic goals is to attempt to recover costs over a longer period with reduced irrigation levels. Restructuring of loans may be possible, since the federal Rural Electrification Administration furnished much of the investment capital for local REAs. We believe these broader concerns should be increasingly recognized in rate-making policy.

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APPENDIX I

Partial Linear Programming Tableau for Evaluating Electricity Rate Structures on Eastern Colorado Irrigated Agriculture

Definitions

Rows

OBJECTIVE FUNCTION - Maximizes returns to land, management, water and the irrigation system

KWH - Kilowatt hours

ELCOST - A special ordered set consisting of columns ENTRY through POINT4

GPWATER - Acre inches of water pumped into a gated pipe irrigation system

LPWATER - Acre inches of water pumped into a low pressure center pivot system

HPWATER - Acre inches of water pumped into a high pressure center pivot system

Input Purchase Activities

RBYDSL - Gallons of diesel fuel purchased

RBYGAS - Gallons of gasoline purchased

RBYNH3 - Pounds of anhydrous ammonia purchased and applied

RBYFER - Pounds of other fertilizer purchased and applied

RNPWC - Non-power water costs that vary per acre inch

Crop Selling Activities

RSLCG - Bushels of corn grain sold (similar activities exist in the full tableau for sugar beets, pinto beans, wheat, sorghum, and alfalfa hay)

Land Constraints

IRRLND - Acres of irrigated land

GPLND - Acres of gated pipe irrigation

LPLND - Acres of low pressure center pivot irrigation

HPLND - Acres of high pressure center pivot irrigation

BTLND - Acres of sugar beets grown

BNLND - Acres of pinto beans grown

Pumping Constraints

PUMAPR, PUMMAY, PUMJUN, PUMJUL, PUMAUG, and PUMSEP constrain the amount of water used in each month of the growing season to the amount that can be physically pumped by the average well.

Columns

ENTRY, POINT0, POINT1, POINT2, POINT3, and POINT4 describe the total cost and total number of kilowatt hours purchased at the end of each block of the rate structure.

GPW, LPW, AND HPW show the number of kilowatt hours needed to pump one acre inch of water through gated pipe, low and high pressure center pivot systems.

CBYDSL, CBYGAS, CBYNH3, CBYFER, and CNPWC give the purchase price for each of the inputs.

CSLCG gives the selling price for corn grain. Similar columns exist in the full tableau for the other crops.

CG = corn grain

GP = gated pipe irrigation

LP = low pressure center pivot irrigation

HP = high pressure center pivot irrigation

F = full irrigation level

5 = five-sixths of full irrigation

2 = two-thirds of full irrigation

1 = one-third of full irrigation

DRY = dryland crop production

Similar crop activities exist in the full tableau for sugar beets, pinto beans, wheat, grain sorghum, and alfalfa hay.

Appendix Table 1. Partial Linear Programming Tableau for Evaluating Efficiency Rate Structures on Eastern Colorado Irrigated Agriculture.

Rows	Unit	Entry	POINT0	POINT1	POINT2	POINT3	POINT4	GPW	LPW	HPW	CBYDSL	CBYGAS	CBYNH3	CBYFER	CNPWC	CSLCG
Objective Function	$	0	-1,575	- 1,575	- 3,379	- 5,579	- 9,737				-1.15	-1.26	-0.13	-0.15	-0.57	3.15
KWH	Kwh	0	0	-11,568	-26,000	-51,000	-150,000	28.17	40.82	52.84						
ELCOST																
GPWATER	ac in							-1								
LPWATER	ac in								-1							
HPWATER	ac in									-1						
RBYDSL	gal.										-1					
RBYGAS	gal.											-1				
RBYNH3	lb.												-1			
RBYFER	lb.													-1		
RNPWC	ac in														-1	
RSLCG	bu.															-1
IRRLND	acre															
GPLND	acre															
LPLND	acre															
HPLND	acre															
BTLND	acre															
BNLND	acre															
PUMAPR	ac in															
PUMMAY	ac in															
PUMJUN	ac in															
PUMJUL	ac in															
PUMAUG	ac in															
PUMSEP	ac in															

Appendix Table 1. (continued)

Rows	Unit	CGGPF	CGGP5	CGGP2	CGGP1	CGLPF	CGLP5	CGLP2	CGLP1	CHGPF	CGHP5	CGHP2	CGHP1	CGDRY	RHS
Objective Function	$	-123.00	-122.00	-121.57	-118.61	-100.62	-100.00	- 99.05	-96.27	-100.62	-100.00	- 99.05	-96.27	-28.82	MAX
KWH	Kwh														=0
ELCOST															=1
GPWATER	ac in	26	22	18	9										≤0
LPWATER	ac in					23	20	16	8						≤0
HPWATER	ac in									23	20	16	8		≤0
RBYDSL	gal.	14.3	14.3	14.3	14.3	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	3.3	=0
RBYGAS	gal.	2.4	2.2	2.0	1.2	2.4	2.2	2.0	1.2	2.4	2.2	2.0	1.2	0.4	=0
RBYNH3	lb.	200	190	180	100	200	190	180	100	200	190	180	100	25	=0
RBYFER	lb.	150	140	135	75	150	140	135	75	150	140	135	75	25	=0
RNPWC	ac in	26	22	18	9	23	20	16	8	23	20	19	8		=0
RSLCG	bu.	130	122	110	65	130	122	110	65	130	122	110	65	10	=0
IRRLND	acre	1	1	1	1	1	1	1	1	1	1	1	1	1	≤128
GPLND	acre	1	1	1	1										≤64
LPLND	acre					1	1	1	1						≤64
HPLND	acre									1	1	1	1		≥32
BTLND	acre														≤7
BNLND	acre														≤7
PUMAPR	ac in	4	3	3		3.5	3	3		3.5	3	3			≤1379
PUMMAY	ac in				3				2				2		≤1379
PUMJUN	ac in	5	4	4	3	4.5	4	3	2	4.5	4	3	2		≤1379
PUMJUL	ac in	9	8	7	3	8	7	6	4	8	7	6	4		≤1379
PUMAUG	ac in	8	7	4		7	6	4		7	6	4			≤1379
PUMSEP	ac in														≤1379

APPENDIX II

Derivation of "Breakeven" Prices

Example - One acre of corn grown with low pressure center pivot at the full irrigation level with January 1982 commodity prices

Gross Revenue (130 bushels x $2.50)	$325.00
Cost of Machinery, Labor, Seed, Ag Chemicals, and Overhead	100.62
Diesel fuel	10.12
Gasoline	3.02
Anhydrous ammonia	26.00
Fertilizer	22.50
Manpower water costs	13.11
Dryland opportunity cost	15.69
	191.06
Remaining Revenue (returns to land, management, irrigation system, and water)	133.94
Kilowatt Hours Required (23 acre inches x 40.82 kwh/ac in)	939 kwh
Short-Run "Breakeven" Rate ($133.94/939 kwh)	14.3¢
Irrigation System Cost	$51.00
Management Cost (.06 x $325.00)	19.50
	$70.50
Remaining Revenue (return to land and water)	$63.44
Long-Run "Breakeven" Rate ($63.44/939 kwh)	6.8¢