Real Time Pricing of Electric Power

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REAL TIME PRICING OF ELECTRIC POWER

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Introduction

The EE 635 course in the School of Electrical Engineering at Purdue University covers the operation and control of electric power systems. The main course elements are economic dispatch, unit commitment, and generation control. Each semester, I ask the students to prepare a term paper on a topic of present interest. The student papers are on different aspects of a given subject. These papers are assembled into a technical report. This semester, the topic is "real time pricing" (RTP), an innovative pricing technique in which the price of electrical energy varies. The concept of RTP allows added "control" of the demand and some proponents feel that the power system can be operated more efficiently. The topics cover RTP techniques, wheeling, cost of energy, and proposed configurations of the RTP technique.

G. T. Heydt
April, 1995
Chapter I

Alternative Real Time Pricing Infrastructures

C. A. Lozano

Introduction

Real Time Pricing (RTP) brings information concerning the time-varying costs of electricity generation, transmission, and distribution to the consumer. The theory of real time pricing was developed under the name of spot pricing [1]. Real Time Pricing of electricity is based on inclusion of time-variable costs of electricity supply in the electricity rates. Under RTP, operation of various end use devices can be optimized in order to capture the savings associated with the variability of prices. The ideal real time price is a combination of the following time-variable components: [10]

- Marginal generation fuel cost
- Marginal generation and network maintenance cost
- Marginal cost of network losses
- Generation and network quality of supply cost

Under real time prices, price patterns and magnitude of prices change every day. The last component can be thought of as a time-variable demand charge which coincides with times of high utility loads. In contrast to demand charges under Time of Use rates, under RTP the highest prices occur closer to the time of supply constraints, and not necessarily during the high period demand for the customers [1]. Real time pricing is also applicable to reactive power, as shown in [8].
This paper is divided in two sections. The first section includes a categorization of prices by two modules, time and price. In the second section is shown some forms of generation and communication of prices to the customer from the utility. At the end of this paper it is shown a table with some companies using combinations of the time and price categorization.

1.1. Categorization of Prices

Three basic reasons are identified in electric market for initiation of rate categories:

- In response to customer demands for additional time differentiation in rates
- To hold off further pressure from regulatory bodies
- To build load or to strategically shift load

**Real time** differentiated rates have two types that are common in the industry: demand charge and interruptible rate. Demand charge is a rate whose full effect is felt in a limited time period, the time at which customer reaches his peak for a given month. For instance, if demand is $5/kW for a month, measured in terms of a 15 minute peak, and the energy charge is $0.03/kWh, then, the effective cost/kWh for the time of peak demand is $5*60min/15min + $0.03 = $20.03/kWh.

**Interruptible** rate is equivalent to time varying prices. For most interruptible rates the customer has agreed (in exchange for a favorable rate structure) to reduce his load in terms of a fixed level of demand. The time at which a customer must reduce his load is determined by the utility, subject to an agreed upon advance warning from moments to days. The value of the interruptible rate to the utility is a function of the amount of warning time that it must give to customers before interrupt. The shorter the warning
time, the more valuable the interruption is to the utility and the more costly it is to the customer.

Electric utilities base the calculation of rates structures in two domains: time and price [11]. There are three basic characteristics in the time domain and two characteristics of rates in the price domain. This is shown in figure I.1. In time domain these characteristics are:

- update cycles,
- time units,
- and warning time.

Update cycle is the length of time that a quoted price is valid. This update cycle reflects the time steps in which a utility operates its major facilities and balances its system. Update cycle is divided in four time steps:

- Zero to sixty minutes update cycles: The utility makes its operating level decisions for individual units and enters into short term purchases and sales with other utilities. This structure is only in existence for utility interchange, but not in existence in rates between a utility and its customers.

- Daily update cycles: These are typical of unit commitment logic for utilities where a forecast of one day is determined. The most commonly seen high speed, high time differentiated utility rate are those with a time unit of one hour. These rates are generally subject to an advanced warning of between 4 and 12 hours. Price increments for these rates are frequently continuous or tiered. The highly time differentiated rate structures are those that are most similar to spot pricing, which attempt to deliver to customers price information based on short run marginal cost and time differentiated information that brings costs and price into line as nearly as possible.
• **Weekly** update cycles: reflect utility time scales of maintenance and refueling.

• Monthly update cycles: reflect utility time scales of maintenance and refueling.

<table>
<thead>
<tr>
<th>Update Cycle</th>
<th>Time Unit</th>
<th>Advanced Warning</th>
</tr>
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<tr>
<td>0 to 60 minutes</td>
<td>1 to 5 minutes</td>
<td>0 to 20 minutes</td>
</tr>
<tr>
<td>Daily</td>
<td>Hour</td>
<td>0 to 4 hours</td>
</tr>
<tr>
<td></td>
<td>Daily time block</td>
<td>4 to 12 hours</td>
</tr>
<tr>
<td>Weekly</td>
<td>Hour to multiple hours</td>
<td>1 to 4 days</td>
</tr>
<tr>
<td></td>
<td>Daily time block</td>
<td></td>
</tr>
<tr>
<td>Monthly</td>
<td>Hour to multiple hours</td>
<td>1 to 4 days</td>
</tr>
<tr>
<td></td>
<td>Daily time block</td>
<td>1 to 2 weeks</td>
</tr>
<tr>
<td></td>
<td>Weekly time block</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Monthly time block</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Monthly time block</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Irregular</td>
<td></td>
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</tbody>
</table>

**Figure I.1.** Time dimensions.

**Time** unit is the period definition or the number of separate prices that are quoted within an update cycle. Thus for the zero-to-hourly update cycle, there are only two **time** dimensions available: 1 to 5 minutes and 1 hour. For the daily update cycle there are three or more time domains, starting from the one hour time unit to a day as a whole. For the weekly and monthly update cycles the time unit is a subdivision of a **week**, such as days or **week** days divided from weekends. Also, for the monthly update cycle the **time** unit goes from days to a month as a whole. The fastest spot price that has been **implemented** is 30 minutes (most implementations involve one hour time steps, which may be prespecified 24 hours in advance) [9].

Warning time is the amount of time in advance of an event that is given to a customer before a cycle changes or before prices are updated. The warning time is a function of the
Length of the update cycle and the time unit. Warning time, as shown in Figure 1.1, goes from a minimal time unit but not greater than half of the whole time unit.

In the price domain there are two significant characteristics: calculation base and price increments. These characteristics are shown in Figure 1.2. Calculation base is the degree to which the price reflects the short run marginal cost. The price calculation is divided in four categories:

- Short run marginal cost based rates are rates derived from the theory of spot pricing. Short run marginal cost pricing structure includes the operating cost, the system cost for generation and the system cost for the network.
The marginal operating cost of serving a particular customer at a particular time is defined as the change in energy and other variable costs that is expected to accompany an incremental change in that customer's load [2]. These costs include those variable costs that may be wholly or partially incurred due to capacity constraints. The factors that determine the marginal operating cost include:

- generation system mix
- individual plant economic and reliability performance
- the cost of fuel
- unit commitment and economic dispatch procedures
- plant and network operating constraints
- losses and demand characteristics

All these factors influence the extent, location, and timing of electricity production. For an estimation of the day-ahead hourly marginal operating cost is necessary to follow the next four steps:

1. Hourly loads and external exchanges with other utilities must be forecast for the next day.

2. All the generating units that are expected to be on dispatch on the following day should be represented with linear incremental cost curves adjusted for losses and transmission constraints.

3. Solve the economic dispatch problem for each hour with area net interchange constraints added to the problem formulation.

4. The forecast estimates should be tracked carefully and validated against actual hourly marginal costs because the marginal operating cost forecasts may be inaccurate due to methodological problems, forecasting errors, or other factors.
- **Operating** cost or system lambda capture the variable operating costs but not any **capacity** costs.
- **Average** cost refers to the cost of service based.
- **Demand/ capacity** cost. Here the rate charged to customers is either the actual demand **charge** or is an equivalent of demand for consumption in excess of a **pre-specified** level. **Demand** cost is also related with marginal outage cost in the sense that the customer must **pay** more when the energy is limited.

**Marginal** outage costs quantify the incremental economic effects of load changes upon the quality or reliability of electricity service. Marginal outage costs depend upon both the economic damages due to outages and upon the risk of outages occurring. Marginal outage costs are the product of outage costs per unit of interruption **times** the change in interruption levels attributable to an incremental change in load. Outage costs can be estimated in several ways, the ideal probably being a combination of the survey and demand- curve approaches. This estimation needs to be undertaken at **very** infrequent intervals, no more than once in several years. Marginal outage characteristics can be forecast using an appropriately designed power- flow analysis program. It can be forecast on a day- ahead basis, and should be re- forecast every day. Because the marginal outage characteristics will change daily, so will forecast marginal outage costs.

Price increments is the number of prices available to customers. Price increments are divided in four categories:
- **Continuous** rate is the level seen by the customer which could **vary from** zero to infinity.
- **Tiered** rate is where there are tiers to the rates, **i.e.**, rates may be level 1, level 2, level 3 out to level N.
- **Interruptible** rate is one in where the source is interruptible, that is, rates are either in **category** 1 or in another level where the second category may be infinite, discrete, or
continuous. In this structure, generally the customer must respond to the utility's request, be penalized significantly or be removed from the interruptible program. The base line rate for interruptible rate is calculated as the marginal or average cost of supplying customers for a fixed amount of time during a year. It is generally calculated in advance based on an expected value of cost and of a cost based recovery of required revenues. Revenue neutrality: is the requirement that the utility's revenue from a customer who is under RTP be the same as it was under the previous rate if the customer's consumption pattern remains the same as it was under the previous rate [1].

The critical element in most interruptible rates is the time of warning prior to interrupt. The shorter the period of warning the higher the value to the utility, and generally, the higher the cost to the customer. Inversely, the longer the time warning, the lower the value to the utility.

- Single rate is a rate that is only at a single level (flat rate).

Also, in the price domain there is a rate structure differentiation that may range from a penalty for noncompliance to an incentive for compliance. This range is divided in three blocks:

- Incentives only
- Incentives and penalty
- Penalty only.

Incentives only is a theoretical definition because the utility does not respond with money or any material incentives to the customer when this follow all the requirements of the supplier. Instead, the utility does not penalize the customer for malfunction of the energy and in hands of the customer is the consideration of violating or not the rules in the agreement with the supplier.
Penalty only is related with demand cost described above. The customer must pay more for the excessive use of electricity in times of high demand, or the customer could be penalized in the form that the supplier does not sell more energy to that customer for determined time.

In pricing of electricity, the price is generated by a combination of the categorization presented here besides other forms of pricing that the supplier and the customer agree. An application of pricing categories is shown in [3]. Next it is a description of one form of pricing taking into account the outage costs.

In the Public Utility Regulatory Policies Act of 1978 appears an ambiguous term which refers to a price a utility must pay to qualified industrial cogenerators for electricity. This term is "Avoided Costs", and it has caused problems because the absence of consistent pricing policy of electricity. From this, many pricing policies of electricity for non utility generated power have arisen. One of this methods is Reliability Differentiated Real Time Pricing (RDP) [7] which present a welfare maximizing policy for pricing non utility generated power. With this method, the purchase price of electrical energy at any time and location is set equal to the utility's marginal cost of supplying electricity at that time and to that location. Also, the price of firm capacity purchase from neighboring utilities, cogenerators, and independent power producers is set equal to the expected value of the marginal capacity cost or the shadow price of the capacity addition at that time and location.

It is assumed that a public utility owns and operates the generating plants and transmission network and it sells electricity to independent customers. Customers could be residential, commercial, industrial, or independent power producers. Utility is assumed to be able to set and communicate prices instantly to the customers and each customer could have
different price. These prices are subject to the cost of generating power and the cost of reliability supply of electricity to customers. One of the main causes of pricing is an outage. Outage cost is defined as the price a customer is willing to pay to avoid an outage. Incurring in an outage, causes problems in to the customer, for instance, in the form of interruption processes. Outage costs depend upon the timing, frequency, duration, and extent of the outage. In [4] there are some algorithms to establish foundations for the determination of the expected costs resulting from system outages.

Figure 1.3. Relations between price of electricity and electricity demand.

Figure 1.3 shows relations between price of electricity and electricity demand. Curve DD shows the expected short run customer demand, D'E is the very short run customer demand curve, SS is the supply curve of electricity, and Qie is the equilibrium demand of customer I at time t for the published expected price Pie. When supply is cut back to Qoi the area D'FE represents the outage cost for the customer, the are under the short run demand curve DD gives the loss in customer benefit, and Poi is the price the customer is
willing to pay in the very short run for continued supply of electricity. Note that the very short run curve is very steep, meaning the customer could pay more to avoid any interruption of electricity [6]. This analysis is also presented for the long run term where it is assumed the utility buys energy at a price $p_t$ and firm capacity $o_t$. Here $p_t$ is the same expected marginal operating cost and $o_t$ is the expected marginal capacity cost. With these considerations it is generated the Lagrangian equations of the system for the consumer maximization problem and for the Welfare Maximization problem (utility). The solutions for these equations show very interesting results, like the independence of the customer's energy consumption and production decisions and the fact that consumer demand is equal to this marginal benefit plus marginal outage cost. Also, the customer will produce electricity to set marginal production cost equal to the price of electrical energy purchase and add capacity until marginal capacity cost equals the price of capacity purchase by the utility. For welfare maximization, the purchase of price of electric energy must equal the marginal cost of producing electricity by the utility, and the purchase price of firm capacity must equal the shadow price of capacity addition for the utility.

1.2. Generation and Publication of Price

Prices for electricity are generated and communicated to the customer in several forms. The generation of pricing depends on the system as well as the type of agreement between supplier and customer. Here there are some examples of how a real time price is generated.

This example is an experiment of scheduling electric thermal storage systems by real time pricing [1, 10]. The experiment was carried out in New York Power Plant. The project used an open loop feed-forward control. The storage charging schedule was set for each site, and after few hours, site data were analyzed automatically in view of new information and a new schedule was determined and set to the site, over- riding the previous schedule.
The control algorithm was composed of two stages. The first stage assumed that the load and the day-ahead price forecasts were accurate, and determined as optimal storage charging schedule under deterministic conditions. A second stage considered the inaccuracy in the future load and price forecasts, and modified the charging schedule by a heuristic based stochastic algorithm using the hour-ahead prices and the measured current tank temperature. This is shown in figure 1.4.

![Data and Calculation Flow](image)

**Figure 1.4. Elements of the RTP Based Control System**
The existing systems handled delivery of heat to the building from the storage tank, while the RTP system controlled the timing of electrical energy into the storage tank. Price and weather information were gathered electronically, the building status was sensed, and a near-optimal storage charging schedule for the building was calculated and activated.

The hardware required for RTP control of the electric thermal storage unit were a computer, modems for communications, a data logger/controller unit, and some sensor to measure the status of the HVAC. The control algorithms resided in the central computer in Cambridge, Massachusetts. At each site, a data logger collected and stored data, and downloaded it to the central computer when called. The data loggers also monitored the storage tank and implemented the control schedule for the site. The central computer supervised and automatically implemented all the site data retrieval and storage, control computations, and site scheduling. It coordinated placing of calls to the sites, the weather service, and to a price file. The computer receives prices from the utility, and outdoor temperature forecasts from a commercial weather service company. The temperature forecast information was combined with the site data to calculate a building load forecast for the next three days. The optimization programs determined the near-optimal storage charging schedules which were uploaded to the sites.

The next example of generation and publication of prices shows some additional services for the customer. Southern Co. and Mississippi Power Co. (MPC) installed an Automated Customer Information Project in order to develop closer ties to their customers by offering flexible time-of-use, real-time pricing and interruptible rates, besides security, appliance control and easy access to metering information [5]. Figure I.5 shows the Utility Customer Network system (UCNet) used by these two companies. This system uses an Ericsson GE-Enhanced Digital Access Communications System to transmit and receive data and voice from the site of the customer to the utility customer network control center. The cost of the communication system is relatively low considering the capacity of
transmitting data and voice, security features, networked communications, and broadcast capability.

The **UCNet** Control Center controls the flow of data between the communication radio system and various applications. The Control Center is a controlling **gateway** to the radio system that allows computers running applications, such as remote meter reading, load control and demand-side management applications, to communicate with meters and other en-use devices. The radio system can transmit and receive voice **and** high speed data up to 9600 baud's within 20 mile radius of the site. The node, rated for up to 300 V ac, contains both an Enhanced Digital Access Radio Communication and a CEBus **power-line modem** and is powered at application voltages on the secondary side of a distribution transformer. The CEBus is an open standard for communications to meter **from** multiple manufacturers and other devices like smart thermostats, dishwashers, **remotely** operated breakers and other consumer apparatus. The power-line modem in the node provides communications to all other CEBus devices along the secondary without additional wiring.
At Mississippi Power Co. there are usually three to six customers on each secondary transformer with higher densities in some areas. By using CEBus power-line communications, the cost of the node is divided among several customers; and serves to decrease the cost for each individual installation.

1.3. Conclusions

Alternative real time pricing includes many forms of pricing and each day appears a new one from the need of a better price for the supplier and the customer. The price that is given to customer is really a combination of one or more categorization of prices. Categorization of prices based on time and price gives the customer and supplier a tool to
generate real time pricing. Other alternative real time infrastructures, besides those described in categorization of prices, are based on outage costs and demand.

The generation of prices not only include a basic categorization, but the relation of present and future constraints and the cost involved in the same generation and transmission. Some examples of generation and transmission of prices were presented. Also, an example of controlling a thermal storage plant by real time pricing is an infrastructure that gives the supplier the alternative of reduce the operating costs and generate a better price for customers. Generation of prices includes a high technology to gather data of variables in the price calculation and to transmit these data to a central computer. The use of new equipment compatible with many home devices improve the speed of reading the consumption of energy and also gives additional services like security, in cases of device malfunction, and advanced information related to future outages.
## Table 1.1. SUMMARIES OF RATES IDENTIFIED IN SOME COMPANIES

<table>
<thead>
<tr>
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<th>Rate Status</th>
<th># customers</th>
<th>characterization</th>
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<tr>
<td>Georgia Power Company</td>
<td>Variable spot price (rate one (VSP-1))</td>
<td>Experimental</td>
<td>-200</td>
<td>Daily update, hourly time unit; four tier, marginal cost</td>
</tr>
<tr>
<td>Georgia Power Company</td>
<td>(supplemental Energy Rate)</td>
<td>Approved</td>
<td>from 50 to 60 industrial</td>
<td>Summer peak period, hourly; marginal cost based with interrupt</td>
</tr>
<tr>
<td>Pacific Gas and Electric (PGandE)</td>
<td>Experimental Real Time Pricing A-RTP</td>
<td>Experimental</td>
<td>3 initially; increasing</td>
<td>Daily update, hourly time unit; continuous average/marginal cost</td>
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<tr>
<td>Pacific Gas and Electric (PGandE)</td>
<td>Agricultural Interruptible (special condition of rate PA-1)</td>
<td>Optional</td>
<td>200: estimate 600 in 1987</td>
<td>Interruptible with customer override, no advance warning; price not marginal cost based</td>
</tr>
<tr>
<td>Pacific Gas and Electric (PGandE)</td>
<td>Commercial Dispatchable (special condition of rate PA-1)</td>
<td>Experimental</td>
<td>New; estimate 200 by 1988</td>
<td>Interruptible with customer override, no advance warning; price not marginal cost based</td>
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<tr>
<td>Southern California Edison (SCE)</td>
<td>Spot Price Experiment</td>
<td>Experimental</td>
<td>3</td>
<td>Daily update, hourly time unit; continuous, experimental estimated future costs</td>
</tr>
<tr>
<td>Houston Lighting and Power (HLP)</td>
<td>Interruptible Service Rate - B (ISB Rate)</td>
<td>Optional to all customers above 5000 kVA</td>
<td>18 (Approximately 700 MW)</td>
<td>Hourly, real time avoided cost based; interruptible with no warning</td>
</tr>
<tr>
<td>Houston Lighting and Power (HLP)</td>
<td>Purchased Power Service Small (PPSS Rate)</td>
<td>Available to small power producers and cogenerators of 100 KW or less</td>
<td>n/a</td>
<td>Hourly, real time avoided cost based; PURPA rate</td>
</tr>
<tr>
<td>New England Electric System (NEES)</td>
<td>TWACS (Two Way Analysis and Communications System)</td>
<td>Experimental</td>
<td>~ 400 customers (residential, commercial, and industrial users on Cape Ann, Massachusetts)</td>
<td>Voluntary interruptible; incentive payment not cost based</td>
</tr>
<tr>
<td>Orange and Rockland Utilities (O&amp;R)</td>
<td>Peak Activated Rate (Residential)</td>
<td>Experimental</td>
<td>Limited to 150 residential customers without electric water or</td>
<td>Peak activated energy surcharge; price loosely based on marginal cost</td>
</tr>
<tr>
<td>Location</td>
<td>Description</td>
<td>Hours</td>
<td>Notes</td>
<td></td>
</tr>
<tr>
<td>--------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>-------</td>
<td>----------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Orange and Rockland Utilities (O&amp;R)</td>
<td>Peak Activated Rate (Small Commercial) Experimental (3-year trial completed)</td>
<td>Limited to 100; maximum year has had 81 participants</td>
<td>Peak activated energy surcharge; price loosely based on marginal cost</td>
<td></td>
</tr>
<tr>
<td>San Diego Gas and Electric (SDG&amp;E)</td>
<td>Schedule A-6 (TOU) optional to all customers above 4500KW</td>
<td>1-20</td>
<td>Hourly update; coincident demand charge</td>
<td></td>
</tr>
<tr>
<td>San Diego Gas and Electric (SDG&amp;E)</td>
<td>Schedule A-EI Experimental</td>
<td>None</td>
<td>Interruptible with override</td>
<td></td>
</tr>
<tr>
<td>San Diego Gas and Electric (SDG&amp;E)</td>
<td>Schedule R-TOU1 (<em>R</em> means &quot;Real Time&quot;) Schedule R-TOU2 Experimental</td>
<td>n/a</td>
<td>Interruptible with override</td>
<td></td>
</tr>
<tr>
<td>San Diego Gas and Electric (SDG&amp;E)</td>
<td>Schedule I-1; Schedule 1-2 Experimental</td>
<td>2</td>
<td>Interruptible with override</td>
<td></td>
</tr>
<tr>
<td>Tennessee Valley Authority (TVA)</td>
<td>Experimental Test Energy Rate (EPE) Experimental (6-month trial completed)</td>
<td>1</td>
<td>Hourly; continuous marginal cost forecast based</td>
<td></td>
</tr>
<tr>
<td>Long Island Lighting Co. (LILCO)</td>
<td>Restricted Demand Service Optional</td>
<td>18</td>
<td>Interruptible with 18 hour warning; demand charge based</td>
<td></td>
</tr>
<tr>
<td>Detroit Edison (Industrial Development)</td>
<td>Optional Independent</td>
<td>n/a</td>
<td>Interruptible; marginal cost override</td>
<td></td>
</tr>
<tr>
<td>Central Electricity Generating Board, U.K.</td>
<td>Time of Day Pricing Experiment Experimental</td>
<td>Unknown</td>
<td>Daily update, hourly time unit; predicted marginal cost</td>
<td></td>
</tr>
<tr>
<td>Swedish State Power Board/Swedish South Power</td>
<td>Unknown Experimental</td>
<td>Unknown</td>
<td>Test range from weekly update with 2-3 daily time units to hourly updates; hourly system lambda plus network costs</td>
<td></td>
</tr>
<tr>
<td>Electricité de France, France</td>
<td>Peak Day withdrawal Option Optional</td>
<td>Available to all customers</td>
<td>Flexible update, 18 hour time unit, short notice advance warning; price is based on estimated marginal cost</td>
<td></td>
</tr>
<tr>
<td>Electricité de France, France</td>
<td>&quot;Modulatable&quot; Option Experimental</td>
<td>Available to HV/VHV customers</td>
<td>Flexible update, pre-specified time unit; short notice advancement warning; price is based on estimated marginal cost</td>
<td></td>
</tr>
</tbody>
</table>
References


Chapter II
Advantages and Disadvantages of Real Time Pricing

P. O. Asare

II. Introduction

Demand-side management (DSM) programs are designed to *induce* modifications in *utility* customer behavior that confer *benefits* on both the customer *and* the system as a whole. Most DSM programs start with a system load modification objective, *identify* one or *several* means of altering customer loads and then attempt to *identify* the customers who might be able to provide individual load changes that will *add up* to the desired system load *modification* [2].

In general, the utility has *difficulty* in establishing a stable, predictable connection *between* system conditions and needs, and DSM program responses [2]. Because utility conditions can vary *significantly from* day to day or even *from hour to hour*, while the effect of DSM programs tends to be less variable, utilities may *want* to have several programs available to meet complex load shaping objectives. However, given the *ambiguity* in individual program response and the possibility for interactive effects among programs, a portfolio of DSM plans may be *difficult* to manage toward *specific* objectives. Consequently, the concept of Real Time Pricing (RTP) of electricity *was* introduced to offset the problems enumerated.

Real-time price is an electricity rate which varies with time in order to reflect the electric utility's time varying costs of generation, transmission, and *distribution* [1]. It helps to improve the economic efficiency of overall operation of the *electric* system. RTP can provide benefits to both the utility and the customers because it *is* a strategic tool *which* provides customers with the same type of cost and load management signals that are *provided* to the electric supply system. It is a critical element in economically efficient *least-cost* strategies because it provides the customer with symmetric signals that encourage both reduction in consumption (high prices) and also increases in consumption
encourage both reduction in consumption (high prices) and also increases in consumption (low prices). This characteristic of symmetry makes it a unique method relative to others in the field of conservation and load management because RTP can be used to dispatch the customers’ load, not merely turn it off when and if required by the utility [1]. In the process of developing and implementing least-cost strategies, RTP can provide significant incremental benefits to existing demand-side as well as supply-side programs.

II.2 Real-time pricing of electricity

Most electric utilities now have in place or intend to offer a wide variety of DSM programs aimed at the full range of utility customer groups and designed to produce many different kinds of customer responses. Many of these programs have achieved their limited load-shaping objectives [2]. However, collectively DSM programs face a dilemma which arises from the tradeoffs among conflicting objectives. Despite the large number of programs available, utilities cannot establish a unique match between their load management goals and their customers’ responses to the DSM incentives [2]. It is often difficult to predict the degree and timing of load response that will result from a program. Some programs will provide beneficial results at predictable and desirable times but lead to extraneous behavior that is undesirable for the system at other times. For example, incentives to reduce daytime use of air conditioners result in less total usage over the daily cycle. However, customers may respond by increasing usage at the peak under the influence of low energy cost.

Real-time pricing of electricity is a relatively new concept in rate design that is currently being employed by several utilities across the country on an experimental basis. Although methods of RTP implementation vary, the basic concept is to price electricity to reflect the actual cost of providing energy at a given point in time. Therefore, a real-time rate communicates to customers the actual cost of delivering energy as it is used. Given this information, efficiency gains may be realized as customers are provided the
opportunity to control their electricity bills by adjusting their consumption to spot price variations.

An RTP rate is typically calculated as a cents per kilowatt-hour charge that is comprised of both a short-run marginal energy cost component as well as a marginal capacity component \[1\]. A different rate for each hour of each day is calculated and provided to customers with enough advance notice to allow them to change their energy consumption accordingly. When adapting this RTP method to an individual utility, it is possible to refine the approach to make the process easier to understand and to administer.

A real-time price is an energy-only rate that tracks the short-run-marginal-cost (SRMC) of delivering electricity during a specific time and at a specific location \[1\]. When employed by a regulated utility obligated to serve all of its customers, RTP is adjusted for full recovery of allowed revenues. SRMC includes marginal costs that are brought about by the last KWh demanded by a customer. Costs reflect real and reactive energy, operation and maintenance, reserve requirements, maintenance of frequency, voltage and other parameters within tolerance \[1\]. Also reflected in the costs are reliability contingency planning related operations and capacity shortage.

Real-time prices are calculated either retroactively or prospectively. When calculated retroactively, they are based on accounting/historical data for analysis purposes. Information on an hourly system lambda, power losses, and instances of capacity shortage is usually available for the preceding few years \[1\]. RTP rates can also be calculated prospectively as a forecast or expectation, based upon the knowledge available at the time of the forecast about the likely state of the system at the time the RTP will be in effect. Forecasts can be short term (i.e. hours to minutes in advance) or long term (i.e. months to years in advance). The longer the forecast, the larger the forecast error and the associated risk premium. Forecasts are obtainable from existing state of the art computer codes such as unit-commitment/short-term-transaction-evaluation software, and production cost simulation software.

The rates for RTP are generally designed to be electronically communicated to customers ahead of the fact. Systems available at present communicate either an hourly
price a day ahead (24 hour look ahead basis), or provide a forecast of the next day’s hourly cost and a firm price for the next hour 20 minutes ahead of the hour. Recording meters are used to keep track of the actual level of consumption during all hours. For systems in which the customer controls the load, as opposed to those in which specific loads are controlled by a computer logic, a print out and/or electronic display is also provided.

By developing pricing systems based on the short-run marginal cost of utility operations, RTP takes the existing, economically efficient scheduling signals presently used by the utility industry and extends them to the customer. In so doing RTP focuses on increasing the overall efficiency of operation of the power system. From the perspective of the customer, it provides the information necessary to develop economically rational strategies for electricity usage. Customers can schedule major loads so as to reduce cost and maximize net benefits. As a result, RTP provides a program enhancement device for customers and for the utility. Existing investment and/or programs involving customer response for peak demand reduction, in response to high demand charges or high peak time of use (TOU) rates, for instance, are now more flexible from the perspective of the customer. Thus, RTP provides information upon which the load can be scheduled based on the need of both the customer and the utility. The customer is provided with the information needed to reduce demand when it is cost effective to do so and to increase demand when it is economically the most attractive.

RTP is not only symmetric in terms of customer load reduction and customer load increases. It is also symmetric with respect to the customer and the utility. Customer cost savings are precisely matched by the reductions in the operational cost of the utility [1]. The response to RTP therefore, unlike the response to either TOU or demand charges, provides either load reduction or load building at the time and at the current cost of supply of electricity. The question is not whether there will be a least integrated utility/customer cost strategy developed, but rather how these benefits will be shared between the utility and the customer.
II.3 Advantages of real time pricing

There are numerous potential benefits to be derived from the real time pricing of electricity. A number of these benefits are listed and briefly discussed in this section.

One of the biggest advantages of RTP is the reduction of the need for additional peaking capacity. Capital expenditure for generation expansion is often enormous and RTP helps to take off some of that burden. At times of low system reliability, considerable benefits are obtained from customers who find ways to reduce load, thereby helping to avoid forced outages. Through the reduction in energy use by customers at system peak and increase of use during off-peak times, the load factor is considerably improved.

Real-time pricing removes the monthly demand charge and limits the high cost of service hours to a relatively few hours during a year [1]. This may provide customers with increased flexibility and choice in their consumption pattern without necessarily increasing their electricity bill. In the absence of RTP, if a customer had high demands even for only a few hours in a month, they had to pay the penalty for the entire month. RTP provides equitable billing without cross subsidies or discrimination among customers. It reflects each customer's impact on its cost of service. Customers are provided with information that allows them to potentially alter their consumption pattern and decrease their electricity costs relative to the value of service to them. RTP gives customers the incentives for altering their consumption patterns in the direction of lower service costs. Thus short and long term prospects for lower cost service are realized.

Nuclear generation units are difficult to operate at less than full output [4]. Once the energy is produced it has to be used since it is also difficult to recycle. RTP helps to minimize these problems since the power is often available at low marginal cost and therefore customers are induced to buy. The utilities in the process have the opportunity to make high profit margin sales.

Deregulation of the utility industry has opened the door for independent generation of power by large industrial and commercial customers. Competition in the industry,
which was almost non-existent before, does put some utilities who cannot offer competitive prices for their power at risk of losing customers. RTP helps these utilities to offer reasonable prices to their customers, and thereby discourages them from buying power form other companies, or generating their own power in some cases.

RTP helps to increase the overall efficiency of electricity generation and consumption. Overall system reliability is also increased due to availability of excess capacity. Marginal outage costs convey information about customers' willingness to pay for reductions in system reliability. Outage charges depend on energy reserve conditions. Using real time pricing mechanisms, ample energy reserves, and hence high system reliability, can be maintained. Therefore, in the majority of hours the outage charge is zero or very small.

In some areas the fuel sources available for generation are depleting and it has become necessary to adopt conservation measures. Some customers in certain cases go through rotational outages as a means of helping to conserve energy. In helping to reduce the need for generation expansion, RTP aids in the conservation of these: depleting natural resources.

II.4 Illustration of customer response to RTP

Niagara Mohawk Power Corporation (NMPC) created the Hourly Integrated Pricing Program (HIIPP) to determine experimentally whether real-time pricing can provide the appropriate customer response at precisely the time it is required. By basing electric service pricing on short-run marginal cost, NMPC wanted to see if it could achieve efficient restructuring of usage patterns under equitable revenue reconciliation arrangements. The HIIPP is a form of RTP but is unique among other pricing programs in two ways. First, it includes a true experimental control group that supports comparative response analysis. Second, customers face hourly energy prices based on marginal cost with no revenue reconciliation factor.
The Hourly Integrated Pricing Program was initiated in 1987. It offers an experimental rate to a limited number of customers who were selected to be representative of NMPC’s large industrial/commercial service class. This class is served by a time-of-use rate. As part of the experimental design, customers were subscribed to HIPP in two phases to permit the second phase of volunteers to serve as a control group for the first.

HIPP customers are diverse and have a variety of electric load shapes [2]. They include paper mills, heavy manufacturing, a brewery, municipal wastewater treatment plants and university campuses. They are regionally diverse as well, spread across Niagara Mohawk’s service territory from Albany to Buffalo. Customer size varies from about 2 MW to over 30 MW, with an average demand in excess of 6 MW. Usage ranges from 15 to 187 million kWh per year, with an average of 50 million kWh per year. As a class, HIPP customers constitute about 2.5 percent of NMPC’s total electric revenues [2].

HIPP customers receive notification of hourly prices by 4:00 p.m. of the preceding business day. Customers then make decisions on the pattern of their electricity use based on these prices. HIPP is a DSM program because it provides an inducement to modify load in a manner desired by the utility. What sets HIPP apart from other DSM programs is that the inducement is a price signal tied directly to time-differentiated system marginal cost, and therefore assures that any customer response benefits the customer, the utility and nonparticipants [2].

The inducement varies on an hour-by-hour basis. It signals the potential for load building at times of high system reliability and encourages conservation at times of low reliability. The system’s status is indicated by means of marginal costs composed of two segments: marginal energy and marginal outage costs. Marginal energy costs are derived from the cost of generating or purchasing and then transmitting and distributing electric power to customers. Marginal outage costs estimate the value of losses to system customers arising from an outage, based on the probability of the next kWh consumed producing an outage and the cost of the outage. Shown in Table 1 is a summary of the retail prices paid by HIPP customers since the program started in April 1988. Prices reflect the seasonal nature of system reliability, with prices generally higher in winter and
suramer than in spring and fall. NMPC experienced temporary capacity shortages in early 1989 and the high prices of electricity shown in the table for that period reflect that situation. HIPP prices have average values similar to the usage charges of NMPC’s industrial time-of-use rate, but they have even highly variable, especially at times of low system reliability.

Table (11.1). HIPP prices compared to standard TOU prices ($/MWh) [2]

<table>
<thead>
<tr>
<th>TOU¹</th>
<th>On peak</th>
<th>Off peak</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Minimum</td>
<td>Maximum</td>
</tr>
<tr>
<td>HIPP²</td>
<td>1988 II</td>
<td>22.90</td>
</tr>
<tr>
<td></td>
<td>1988 III</td>
<td>31.08</td>
</tr>
<tr>
<td></td>
<td>1988 IV</td>
<td>31.79</td>
</tr>
<tr>
<td></td>
<td>1989 I</td>
<td>34.34</td>
</tr>
<tr>
<td></td>
<td>1989 II</td>
<td>30.44</td>
</tr>
<tr>
<td></td>
<td>1989 III</td>
<td>33.11</td>
</tr>
</tbody>
</table>

Note: On-peak and off-peak periods are defined by NMPC’s TOU rate. On-peak: 8:00 a.m.-10:00 p.m. on all non-holiday weekdays. Off-peak: all other hours.

¹These are the prices for service under the company’s large industrial service time of use service classification, SC-3A. All HIPP customers converted from SC-3A to HIPP and revenue neutrality under HIPP is defined in terms of embedded cost allocations for that class.

²Price is an average of rates charged to the first 9 customers joining HIPP.

Niagara Mohawk’s HIPP rate provides a clear signal directly to customers, of conditions within the system. This signal is their sole inducement to engage in load-modifying behavior. If such load modifications occur, they are unambiguously beneficial to the utility and to other customers connected to the system. The basis of the HIPP is the price signal, based on day-ahead forecasts of marginal cost. HIPP is unlike other real-time rates in that retail price is set equal to short run marginal cost and contains no additive or multiplicative factor for revenue recovery [2]. Instead, the rate is based on two-part
pricing theory. The **first** part is an energy charge, consisting of marginal cost on an hourly basis, adjusted for transmission losses and taxes. The second component is a lump sum "access charge," a unique feature that assures customer-specific **revenue** neutrality and **fulfills** the overall revenue requirement.

The access charge is a fee, paid monthly, and set such that the customer's HIPP **bill** exactly equals the TOU bill that the customer would have paid had they remained on that rate and maintained the level of usage established by the "customer baseline load (CBL)." The **CBL** consists of an 8,760 hour load profile established by each customer during the July 1, 1986 - June 30, 1987 period. These loads are **conformed** to the current **calendar** to match days of the week in the base year to those in the current year, thereby taking into account the need to align weekdays, holidays and shutdowns. Thus, the access charge is derived from a bill calculation based on actual HIPP prices, TOU prices and **baseline** load and it equates TOU and HIPP bills at baseline load. Each customer is therefore revenue neutral at his baseline load, with revenue neutrality **defined** in terms of historical usage. In practice this means that the customer effectively pays the real-time price (short run marginal cost) on incremental load above CBL in each hour. In addition, **decrements** in load below CBL credit the customer's bill at the same real-time price.

Strategic load growth is desirable to the utility at times of high system reliability. Such growth distributes embedded costs over a larger load base, thereby reducing rates. A DSM program with this objective seeks to induce customers to increase usage when energy is available with plenty of reserve margin. Generally this **occurs** during off-peak periods as defined by system marginal costs.

HIPP customers engaged in **significant** strategic load growth, as indicated by the results shown in Table (II.2). The table compares Phase 1 customers' **load** growth in the **lowest** priced hours with growth during the entire first year of the program. During the 25 **lowest** priced days of the year, HIPP customers increased **consumption** by 3.7 million kWh or 11.69 percent, while loads increased by 12.7 million kWh or only 2.87 percent **during** the entire year. This pattern of load growth at low prices is **evident** in the quarterly breakdown as **well**, with growth during the lowest priced **five** days outperforming the
entire quarter. Only the **high** priced first quarter of **1989** showed **little** difference in the **rate** of load growth.

Table (II.2). HIPP energy usage: low priced and high priced days vs. **all** days [2]

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Average HIPP price ($/MWh)</th>
<th>CBL</th>
<th>Actual</th>
<th>Difference</th>
<th>Difference (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Lowest priced days in quarter</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1988 II</td>
<td>25.22</td>
<td>6,182</td>
<td>7,106</td>
<td>924</td>
<td>14.95</td>
</tr>
<tr>
<td>1988 III</td>
<td>31.72</td>
<td>6,430</td>
<td>6,758</td>
<td>327</td>
<td>5.09</td>
</tr>
<tr>
<td>1988 IV</td>
<td>34.89</td>
<td>5,703</td>
<td>6,462</td>
<td>759</td>
<td>13.30</td>
</tr>
<tr>
<td>1989 I</td>
<td>40.71</td>
<td>5,944</td>
<td>5,998</td>
<td>54</td>
<td>0.91</td>
</tr>
<tr>
<td><strong>25 lowest priced days overall</strong></td>
<td>28.16</td>
<td>31,634</td>
<td>35,332</td>
<td>3,698</td>
<td>11.69</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Average HIPP price ($/MWh)</th>
<th>CBL</th>
<th>Actual</th>
<th>Difference</th>
<th>Difference (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Highest priced days: in quarter</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1988 II</td>
<td>78.14</td>
<td>6,670</td>
<td>6,243</td>
<td>-426</td>
<td>-6.39</td>
</tr>
<tr>
<td>1988 III</td>
<td>111.67</td>
<td>6,327</td>
<td>5,014</td>
<td>-1,313</td>
<td>-20.76</td>
</tr>
<tr>
<td>1988 IV</td>
<td>78.08</td>
<td>5,159</td>
<td>6,276</td>
<td>1,116</td>
<td>21.64</td>
</tr>
<tr>
<td>1989 I</td>
<td>109.48</td>
<td>6,072</td>
<td>5,121</td>
<td>-951</td>
<td>-15.66</td>
</tr>
<tr>
<td><strong>25 highest priced days overall</strong></td>
<td>92.24</td>
<td>29,618</td>
<td>28,294</td>
<td>-1,323</td>
<td>-4.47</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Average HIPP price ($/MWh)</th>
<th>CBL</th>
<th>Actual</th>
<th>Difference</th>
<th>Difference (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>All days quarterly summary</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1988 II</td>
<td>35.22</td>
<td>114,364</td>
<td>122,858</td>
<td>8,495</td>
<td>7.43</td>
</tr>
<tr>
<td>1988 III</td>
<td>45.62</td>
<td>116,400</td>
<td>110,009</td>
<td>-6,391</td>
<td>-5.49</td>
</tr>
<tr>
<td>1988 IV</td>
<td>44.63</td>
<td>108,564</td>
<td>119,086</td>
<td>10,522</td>
<td>9.69</td>
</tr>
<tr>
<td>1989 I</td>
<td>54.98</td>
<td>101,946</td>
<td>102,003</td>
<td>58</td>
<td>0.06</td>
</tr>
<tr>
<td><strong>All days total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>45.11</td>
<td>441,274</td>
<td>453,957</td>
<td>12,684</td>
<td>2.87</td>
</tr>
</tbody>
</table>

Strategic load growth is also evident in the pattern of load **shape** changes in periods of low prices. One such period was April **1988**. Figure (11.1) depicts the pattern of actual and baseline usage by the average Phase 1 HIPP customer on weekdays during that month and provides a graph of average HIPP and TOU prices for that period.
Average loads increased in every hour, but increased more strongly during on-peak hours (in the TOU sense) than in the off-peak period. Thus, the TOU rate was suppressing demand during periods when there was no cost-based reason for doing so.

Average hourly loads - weekdays

Average hourly prices - weekdays

Figure (II.1). Average phase 1 HIPP customer (April 1988) [2]
Table (II.2) shows that in the year's 25 most expensive days Phase 1 HIPP customers reduced loads by 4.47%, in contrast to the 2.87% load growth registered during the full year. The contrast between the 25 highest and lowest priced days is even greater, a difference of over 16 percent.

Figure (II.2) demonstrates the effectiveness of marginal cost-based pricing in helping to reduce peak use. It illustrates HIPP prices and the baseline and actual loads of a HIPP customer on August 3, 1988, which happens to have been the summer system peak. Knowing that prices were going to be high for the day, the customer reduced load significantly below baseline, especially between 6:00 a.m. and 2:00 p.m. The largest load reduction in any hour was about 80 percent. Although the customer did not sustain this degree of reduction throughout the day, it provided some load relief in every hour of high prices. HIPP customers responded with significant reductions below their baseline use whenever HIPP prices were high; the degree of response increased with real-time price.

Consider the hour of highest HIPP prices to date, shown in Table (II.3), for March 8, 1989. In both this hour and the August 4 summer price peak shown in Table (II.3), HIPP customers reduced usage by approximately 35% in response to strong marginal price signals.

<table>
<thead>
<tr>
<th>Peak hour</th>
<th>HIPP price ($)</th>
<th>Usage (MWh)</th>
<th>Difference</th>
<th>% Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date, hour</td>
<td>CBL</td>
<td>Actual</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spring peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tuesday, March 08</td>
<td>396.13</td>
<td>56.5</td>
<td>37.2</td>
<td>-19.3</td>
</tr>
<tr>
<td>Summer peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Thursday, August 04</td>
<td>239.31</td>
<td>49.8</td>
<td>31.8</td>
<td>-18.0</td>
</tr>
</tbody>
</table>
Another look at Table (II.2) confirms that this is neither a phenomenon restricted to the most expensive hours nor a chance event. In the 25 days (or 600 hours) of highest average price during the first year of HIPP service, customers reduced load by approximately 1,323 MWh or 2.2 MW per hour. This translates into about 25 MW in each hour for the average HIPP customer.

The responses by HIPP customers to the experiment indicates that they are able to respond to day-ahead marginal cost-based pricing. By taking advantage of price differentials over time, they have produced significant DSM benefits for the Niagara Mohawk system and its customers. Furthermore, the value of these benefits appears to
increase with the size of the price signal. This is especially evident in hours of HIPPP price peaks, when HIPPP customers provided significant load relief to the system.

II.5 Potential drawbacks of RTP

Despite the numerous potential benefits that can be derived from spot pricing of electricity, there are some disadvantages associated with it. One major problem with spot pricing is the expensive equipment needed to provide the pricing signals to customers. In some cases they may be difficult to install, and additional expenditure would have to be made for the purpose of educating customers on their use.

Under real-time pricing, the consumption behavior of every utility customer may affect the prices faced by all other consumers [3]. Through consumption behavior, each utility customer can affect marginal generation costs (which are non-linearly related to demand), pollution emissions, and the quality attributes of electricity (harmonic distortion, frequency, etc.). Each customer can also affect the balance between demand and available capacity for power generation, transmission, and distribution. This is the so-called "obnoxious" neighbor problem.

The problem can be illustrated by a case of two price-inelastic customers served through a radial transmission line. If both customers have equal annual consumption, but customer A's demand for electricity fluctuates very little (A has a high load factor), while customer B’s demand is very volatile, then customer A may be adversely affected by B’s consumption behavior. Assume that the transmission or distribution line serving the two customers has a capacity which is adequate to serve the combined average demand of the two customers, but is inadequate to accommodate loads which are higher than their combined average demand. In this case, no transmission congestion charges will be assessed on either customer as long as B’s demand remains at or below its average level. However, a transmission congestion premium will be charged to both customers A and B whenever B’s demand is higher than average. In a sense, customer A is paying part of the cost associated with customer B’s demand volatility.
Another problem (and one which is by no means unique to a real-time pricing system) involves the state of the system and network [3]. Every location in the network enjoys a different status. Greater transmission and distribution system capacity will be available in some locations in the network than in others. Some customers will face the “obnoxious” neighbor problem. The age and efficiency of the utility system equipment will differ among various geographical locations in the network. The state of the system at a particular customer's location will affect the prices that the customer will face. A customer in a slow growth area, an area where growth expectations did not materialize, or an area with relatively newer facilities will likely face lower prices than a customer in an area where congestion charges or other premiums must be frequently applied to ration available supply.

Power wheeling may put different customers in a power pool at a comparative advantage or disadvantage. For a simplified "bus to bus" wheeling transaction, the optimal wheeling price (to be paid to the wheeling utility) is the difference in optimal prices between the two locations [5]. Consummation of the wheeling transaction may affect the optimal prices at every other location of the network. The change in power flows throughout the network will cause the optimal prices faced by some consumers to increase and will reduce prices to others. If the party desiring the wheeling transaction were required to compensate all customers whose welfare were inadvertently affected by the transaction, then incorrect price signals might be sent.

Theoretically, the premiums and charges collected through real-time pricing are expected to be used toward alleviating the constraint that prompted their assessment. For example, the utility revenues collected through pollution emissions premiums would be dedicated toward pollution abatement. However, ensuring that the revenues collected through premiums and charges are actually dedicated toward such investments may prove difficult due to indivisibilities and other factors. For example, it may be difficult to ensure that the revenues collected in one region of the network are not used to excessively subsidize ratepayers in other locations. Inevitably, it will be necessary to use some revenues from current ratepayers to construct facilities for future ratepayers.
In an area where there is a majority of customers whose demand for electricity is price-inelastic, spot pricing of electricity may lose its effectiveness. This is because there will be no incentive for these customers to either reduce consumption during system peak hours, or to increase consumption to take advantage of low energy prices during off-peak hours.

II.6 Summary

In an era when there is immense pressure from government regulatory agencies and environmental groups on utility companies to find new ways of conserving natural fuel resources, RTP has become a tool of utmost importance. Real-time pricing provides an economically efficient means of incorporating existing electric utility supply-side least-cost power strategies onto the customer side of the meter. RTP provides the utility with a means of communicating information to the customer that can be used by the customer to plan and operate his/her facility so as to minimize cost or maximize output while fully compensating the utility for the costs of service. As such, RTP provides additional benefits to the operation of existing customer side investments and/or programs as well as providing incentives for new programmatic investments. Because the system is symmetric to the customer, it encourages reduction in demand when prices are high and increase in demand when they are low. Also, because it is symmetric between the utility and the customer, it provides the basis for development and operation of least-cost strategies within the integrated system that includes both supply and demand side of the electric power industry.
REFERENCES


Chapter III

Advantages of Real Time Pricing
for Electric Power Utilities

III.1 Introduction

The demand for electric power grows every day, but the construction of new generation facilities and new transmission lines has been delayed by energy, environment, right-of-way, and cost problems. The utilities rely on the utilization of power import/export arrangements to solve this problem. But the demand in a system is not always a constant high level; the load duration curve has peaks and valleys [2], as can be observed in figure (III.1). The peaks occur for some periods during the day. Nevertheless, the power system is designed to meet the peak demand plus a reserve margin for reliability purposes.

Figure (1.1): Load Duration Curve for a 24-hour period
Since the demand increases, but the number of generation plants do not, it is highly desirable to use existing facilities as efficiently as possible. If the demand curve is modified, the efficiency of the system would improve.

Most utilities have some kind of program in which the customers agree to limit their loads in return for a special rate [3]. The main objective of these programs is to modify the load to achieve one of the following responses from the consumers: Conservation, load shifting, peak clipping, valley filling, and load growth [1]. Examples of these Demand Side Management (DSM) programs are the electric thermal storage, and the operation during off-peak hours. But the response of the customers to DSM incentives does not always match the load management goals established by the utilities.

Real Time Pricing (RTP) seems to be a way of inducing modifications in the customers' use of energy at times needed by the utility company. The basic idea of RTP is to vary prices during the day, and informing those prices to the customers. Under a constant rate, a customer may rise the load at any time, without any effect to his operation. But if prices vary, the customers will be more cautious about when to increase their use of energy.

In this chapter, Real Time Pricing schemes will be described. Then, the advantages of RTP programs to electric power utilities will be discussed. Finally, a novel method to control load frequency using RTP will be presented.

III.2 Real Time Pricing

Real Time Pricing (RTP) is a service in which prices vary over time, based on projected supply and demand conditions. The electric utility calculates time differentiated prices, and communicates these control signals to the customers. The main objective of RTP is to build load when the system is in off-peak periods, and to shift load from peak hours. This represents a valuable tool for utilities wanting to achieve control of their loads.

Another motivation for RTP is to increase the services available to customers. RTP benefits the customers because they can buy cheaper power at low-priced periods, or diminish their use of energy at high cost intervals. RTP tariffs also make an utility more attractive to customers. This is headed to combat cogeneration. Customers may consider
III.3

to construct private generation facilities due to the utilities lack of diversity in the rates. RTP can also be used by the electric utilities to hold off further pressure from regulatory bodies as the Public Utility Commission.

The rates in RTP have characteristics in time and price domains [4]. These characteristics determine the intervals in which time differentiated prices will become available to the customer. Figure (III.2) shows the divisions in the time domain. The updated cycle is the length of time that a rate is valid. The time unit is the number of separated prices that are quoted within an updated cycle. The advanced warning is the time the customers have to adjust to a new rate. An update cycle of minutes is used by the utilities just for economic dispatch, and for power interchange with other companies. The weekly and monthly cycles are usually used for maintenance and refueling purposes. The most common update cycle used for RTP is a daily interval. For example, prices for tomorrow are calculated today, and the number of prices depends on the time unit chosen. The customers have access to the prices of tomorrow as early as 12 hours in advance, (depending on the agreement reached with the utility.

<table>
<thead>
<tr>
<th>UPDATE CYCLE</th>
<th>TIME UNIT</th>
<th>ADVANCED WARNING</th>
</tr>
</thead>
<tbody>
<tr>
<td>MINUTES</td>
<td>1-5 MINUTES</td>
<td>0-20 MIN.</td>
</tr>
<tr>
<td>DAILY</td>
<td>HOURLY</td>
<td>0-12 HRS.</td>
</tr>
<tr>
<td>WEEKLY</td>
<td>3-5 BLOCKS</td>
<td>1-4 DAYS</td>
</tr>
<tr>
<td>MONTHLY</td>
<td>DAILY TIME BLK WEEKLY TIME BLK MONTHLY TIME BLK MONTHLY IRREGULAR</td>
<td>1-2 WKS.</td>
</tr>
</tbody>
</table>

Figure (III.2) : Real Time Pricing Time Divisions
In the price domain, the most important property is the extent to which price models the short run marginal cost. Calculation of the price includes the operating cost, the system cost, and the cost for the network. There are other methods to determine price, one method use the average costs rather than the marginal costs to determine the rate. In the demand charge method, the customer is billed for the excess in consumption of a pre-specified level of power. Another method uses just the operating cost to set the prices. There are also price increments, levels in which prices are set. These are the prices which are available to customers.

There are other approaches to set RTP rates. One alternative approach accounts for consumer respond to the prices, as well as the impact of their respond to system costs and capacity [5]. Other method includes capital costs in the RTP rate determination [6]. All these approaches point into the same direction: The use of time and cost of energy to develop new rate structures. The choice of which rate to use depends on the specific need of the utility.

Real time pricing programs are currently at an experimental phase. RTP is an area of intense research, and new concepts are being studied. There is a belief that customers cannot adapt to real time prices. Nevertheless, customers have responded in a positive way to such rate diversification efforts. The Niagara Mohawk program is an example of a successful implementation of an RTP program [1]. In this program, the utility had the opportunity to deal with the experimental and a control group. This was a great opportunity to measure first hand, the success of the program. RTP ideas are not limited to the United States. There are also RTP-like programs in Canada, Sweden, France, Australia, United Kingdom, and Finland.

As can be deduce from the discussion above, there are many types of RTP programs. Therefore, the implementation of time differentiated rates depends upon the type of customer, and the electric utility providing the service. Hardware difficulties is the main constraint for RTP programs. These include the equipment used for control and communication of the price signals. Such problems have forced the cancellation of some programs because the requirements of customers and utilities were not met [4]. In the other hand, some industries cannot start RTP programs because of the nature of their businesses. RTP offers a wide variety of markets because it is not limited to industries.
For example, there are RTP residential programs in Georgia [4]. Obviously, implementation of RTP is more complex in this case because of the *quantity* of customers involved.

### III.3 Real Time Pricing and the Electric Utilities

The major challenge of any Demand Side Management program is to match the needs of the *utilities* to the response of the customers to such program. Real Time Pricing achieves this objective by varying the service rate during the day, announcing periods for load building at *times* of high system reliability, and encouraging conservation during times of low reliability. In many situations, a program that encourages load growth *does* not contribute to conservation of energy. But an RTP scheme may accomplish both conservation and growth of load. Thus, RTP is an effective load management tool for the *electric* utilities.

Another advantage of the use of RTP is in the generation reserve. By achieving greater ability to transfer the system load from peak to off-peak periods, the generation reserve *may* be increased. This will also help improve the reliability of the system, because more resources would be available to meet the demand in case of an emergency situation. It is the scale of response and adaptability to the full range of utility *reserve* situations that *makes* RTP an important tool.

RTP rates can also increase utility revenues, and lead to a more *efficient* use of power supply and delivery systems. If the peak demand of a system is diminished, construction of *new* generation facilities is delayed. Shifting the peak demand results in a flatter load duration curve, which increases system efficiency. For example, instead of running the *system* at 85% for 2 hours (peak period), and at 65% the rest of the time, the system may operate at *75%* all the time. Obviously, this increases efficiency and profits.

RTP rates may help electric utilities to keep market share. Innovative rates may enable *utilities* to be more responsive to customer needs. RTP offers flexibility to the customers by giving another option for operating decisions and planning. This *way*, the customers *become* more competitive, and attractive to their own clients. Providing better service to *customers*, the utilities remain in a better position than other options the customers may consider (e.g. private generation). In the *Niagara Mohawk experiment*, customers bought...
more power than the power baseline originally contracted [1]. In this case, RTP rates improved the revenues of the utility.

Another area in which RTP rates may be used is in the pricing of reactive power reactive power. The pricing of reactive power has received little attention. Nowadays, power factor penalties are the common way of "pricing" reactive power. But power factor penalties are not always the most adequate reactive power pricing policy. Real time prices can be applied to reactive power using a modification of the optimal power flow model [7]. Under such scheme, VARs would be treated as another electricity market commodity.

Information gathered through RTP programs is used for resource planning and operation of a power system. In system planning studies, construction of new facilities and allocation of (available resources are directly affected by an RTP program. In system operation, RTP brings another tool for the technicians when emergency situations arise.

RTP programs can be kept administratively simple. An agreement is reached with the customer in terms of the power baseline to be used during the year. The rest of the program implementation is based upon existing processes. RTP is just added to the existing tariffs available to customers.

Real Time Pricing extends the time-of-use (TOU) rate concept by increasing the number of costing periods, and shortening the lead time for setting the rates. TOU rates may suppress demand during periods when there is no cost-based reason to do so. In the other hand, RTP fosters conservation or load growth whenever the utility needs either response.

III.4 Use of RTP in Load Frequency Control

When the demand in a system increases, there is a decrease in system frequency until the generation may be increased to meet the load. This frequency deviation occurs because some of the load increase is met using the inertia of the rotating devices in the system. Automatic Generation Control (AGC) is used to keep the frequency and tie line power flows at their proper values [8]. But the response of AGC to a sudden load increase is not instantaneous. The frequency still deviates from the desired value until AGC detects the anomaly, and initiates a control action. A methodology for the control of load frequency
anti tie line deviations has been presented. This method uses real time pricing as a control mechanism [9].

Spot pricing of electricity neglects the effects of power system dynamics involving frequency or voltage. Only Kirchoff's laws for network flow are considered. The authors in reference [9] discuss pricing on time the time scale of seconds to control frequency deviations. They assume that the technology to monitor real time prices is available, and operating at loads and generators. These devices react to time varying prices. The response to price is pre-set by the user. The computation time is assumed to be zero.

The objective of pricing policy is to maximize social welfare. In other words, to maximize consumers' plus producers' surplus, subject to the operational constraints. The problem is to find the price at which the loads and generators would respond in such a way that frequency and tie line deviations are controlled.

The authors showed that the price for generation, and the difference in price between areas satisfy differential equations that are driven by penalty functions for frequency and tie line deviations. Working on the assumption that the utility knows the optimal controls to solve the social welfare problem, they reached a balance between utilities' profits and social welfare (in terms of electricity pricing). Under this correlation, they showed that the price of electricity is determined by the concern on frequency deviation. If frequency deviation did not matter, there would be a free source energy. This would mean that there is infinite stored energy in the generators. For a detailed mathematical development, refer to [9].

To overcome the time that would be spent by transmitting the real time price, the control devices in private generators could detect the frequency deviation. Operating on the principle that an increase on frequency deviation implies an increase in electricity price, the private generators would increase their own generation to help reduce the deviation. This eliminates the problem of how the utility could compute and transmit the price faster than the phenomenon to be controlled. For further information on non-utility generated electric power, refer to [10].

In terms of the demand, a control device at the loads would automatically monitor price, anti at times pre-set by the customer, turn the load on or off. For example, consider a
Figure (III.3) : Frequency Deviation

Figure (III.4) : Deviation in Mechanical Power of Utility Plants
system with demand = 0.7 pu, and with 10% of its customers in RTP. For a step increase in demand equal to 0.05 pu, the demand would be equal to:

\[ D(t) = 0.05 - 0.07p(t) \]  

where \( p(t) \) is the deviation in price.

Figures (III.3) and (III.4) are from Reference [9]. The difference in frequency deviation between a system response with RTP, and a system without RTP is shown in figure (III.3). The parameters involved in the system frequency control may be varied to achieve a better improvement in frequency deviation. The overshoot of mechanical power in figure (III.4) was eliminated using RTP. Without pricing, this overshoot was necessary to bring frequency back to its set point. This action is shifted to the private generators with pricing.

Although there are many assumptions made in this method, the concept itself deserve further study as an alternative or complement to AGC. It also shows the diversity of applications that Real Time Pricing may have when implemented in a power system.

**III.5 Conclusions**

Real Time Pricing of electricity emerges as a Demand Side Management option to modify customers load at times needed by the electric utilities. RTP is therefore a tool to control system demand. The main objective of RTP is to build load during off-peak periods, and to shift load from peak periods. This would make flatter the demand curve, which helps to improve system efficiency. The reserve margin increases, reliability increases, and the overall system efficiency increases. Shifting the peak demand results in a delay for the construction of new generation facilities.

RTP offers flexibility to the customers. It promotes customer service, and encourage customers to manage their load in a manner that leads to a more efficient use of power supply and delivery facilities. Diversifying the rates available to customers enhances the ability of the utility to provide solutions to daily customer service problems. This keeps the utility attractive to customers, as compared to private generation.
**RTP** provides a load management tool for the utilities, and it may also increase the revenues. By offering variable rates, the customers would be more likely to use energy during off-peak intervals. **RTP** programs would complement, maybe in a future substitute, existing pricing policies as the TOU rates.

Although many companies cannot participate in **RTP-like** programs due to the nature of their products, those participating have expressed their satisfaction with the service. This, together with the advantages discussed above, make Real Time Pricing an attractive and feasible option for the electric power utilities.

**References**


IV.1

Chapter IV

Non-Utility Generation
(Open Access and its Issues)

A. W. Galli

IV.1 Introduction

Since the Public Utility Regulatory Policies Act (PURPA) in 1978 and the subsequent National Energy Policy Act (NEPA) in 1992 the electric power market, in principal, has gone from a regulated group of monopolies to a free, competitive market. Title VII of NEPA, which mandated changes in the structure of the electric power industry came about after more than a decade of debate and is essentially based on economic theorizing rather than engineering design and experience [1]. This is basically summed up in the words of Richard E. Disbrow, Chairman of the Board and Chief Executive Officer of American Electric Power Company, Inc., when he says, "One thing seems certain, that we have another lawyer's relief act [1]."

This paper will give the reader a good overview of the idea of non-utility generation (NUG) and the ideas and problems associated with the concept of a competitively based electric power market. (Note that a NUG is sometimes referred to as an independent power producer (IPP) or, in some cases, as exempt wholesale generation (EWG). This paper will use the appropriate acronym as it fits within the context.) First the paper will give a brief history of utility regulation and how it has changed with PURPA and NEPA which have given way to what is commonly referred to as transmission open access (TOA) or, as it is sometimes referred to, open access (OA). Open Access can basically be broken down into two areas: (1) economic issues, and (2) operational issues. This paper will discuss both of these issues with respect to the current literature and will also contain sections for the following topics: wheeling of power, pricing methods, and security issues. The previously mentioned topics are by far the most pressing issues facing utilities and IPPs. Since NEPA, the electric utility industry has been in a state of flux and
IV.2 Utility Regulation

Although utility regulation and open access issues are not limited to the United States, the focus of this section will be on the past and present legislation concerning the power industry in the United States. It should be noted here that Perez-Arriaga, Rudnick, and Stadlin [2] give an excellent survey of international open access experiences from Europe, South America, Canada, Australia, New Zealand, and the United States.

The electric utility industry began in the United States in 1882 when Thomas Edison commissioned the Pearl Street Station. This opened the door to entrepreneurs who jumped at the opportunity to make a profit. One of the first major regulations passed was the Public Utilities Holding Company Act of 1935. This act assigned franchised territories to power producers with the “responsibility to serve” in return for the elimination of competition. This not only prohibited utilities from participating in any business except producing and distributing power for their customers but also barred NUGs from the market. This act also empowered the Federal Energy Regulatory Commission (FERC) to set rates, terms, and conditions of access for power transferred between systems (wholesale wheeling). [3].

For many decades, the practice of wheeling was carried out through informal contracts between neighboring utilities which helped to ensure cooperative system planning. The utilities liked this form of being intertied, and it worked. However, in 1967 the New York blackout occurred and the security of the electric transmission system was brought into the public spotlight. It was this incident that caused the federal government to create the North American Electric Reliability Council (NERC) to help ensure a reliable electric transmission system in the United States. NERC used its power to create nine regional reliability councils that were responsible for regional transmission planning. The purpose of these councils was not to create any super transmission “highways,” but rather...
to make sure that the regional transmission system was correctly designed and could withstand first and second contingency failures without disastrous consequences. [3].

By the early 1970s, the traditional strength and stability of the mighty utility monopolies was beginning to break down under political and economic forces which caused a once steady increase in load demand to come to an end. In addition, rising inflation, interest rates, and construction costs were causing many utilities to fall into financial crisis as their generation construction plans were coming to completion but load demand was not on the increase. [4]. This, of course, caused energy rates to rise and subsequently be passed on to the utilities customer. The costs finally became such a burden to industrial production that something had to be done. As a reform, the Public Utility Regulatory Policies Act of 1978 (PURPA) was passed. This policy dictated that utilities give consideration to other sources of generation. PURPA, combined with a new emphasis on the environment, started a trend in energy conservation and opened up the doors for IPPs (usually in the form of industrial co-generation) to enter the utility market. [3], [4]. According to the Electric Generation Association (EGA), an independent power producer trade association, this shift toward IPPs helped to stabilize and reduce costs from historic heights [4]. Yet, the success of PURPA, according to the EGA, was that its limitations were highlighted in practice. Under PURPA, utilities were only required to purchase from qualifying co-generators and small power producers (hereafter collectively referred to as qualifying facilities (QF)) at rates that are: (1) just and reasonable to the utility's customers and in the public interest, (2) non-discriminatory with respect to QFs, and (3) not in excess of the incremental cost to the electric utility of alternate electric energy [5]. The qualifications for being a QF, however, were still mandated by the 1935 PUHCA. However, QFs could avoid these mandates by meeting efficiency, thermal usage, and ownership criterion. If a QF met these conditions, a utility was required to purchase the QFs power. An interesting note, however, is that a utility may own up to 50% of a QF project and currently there are more than 35 utilities actively participating in QF projects; many making very good returns. Despite the required complicated
arrangements and approvals required to comply with PUHCA, IPPs did find ways to sell wholesale power under the reform of PURPA. [4].

It soon became clear that more reform was needed to build an effective competitive market. On October 5, 1992 Congress passed Title VII, Subtitles A and B of the Comprehensive National Energy Policy Act (NEPA). This policy dictated open access (OA) without regard to method, plan, or compensation [1], [3]. Put simply, FERC now has the authority to order wheeling and access. That is, any utility, federal power marketing agency, or any other person generating electric energy for sale at wholesale may apply to FERC for an order that would require a transmitting utility to provide services to the applicant [1]. NEPA does not mandate that the order for access be issued, just that it be considered. Whenever FERC sees that the transaction would be in the best interest of the public, an order may be issued. Also, if FERC finds the transaction to be beneficial, yet recognizes that the access may cause lack of security in the transmission system, they may order the wheeling utility to build additional transmission. [1]. Figure IV.1 gives the reader a rough time-line of major happenings in the electric utility industry.

![Figure IV.1 Time-line of Major Policies Affecting the Electric Utility Industry](image)

Currently, IPPs are gaining an increasing share of the power supply market and are now playing a significant role in the planning, development, and construction of new
generation facilities in the United States. NEPA further opened the door for IPPs to enter the wholesale power market as exempt wholesale generators (EWGs). This new breed of IPP is legislated by NEPA because of NEPA’s allowance for open transmission access (wheeling) under the jurisdiction of FERC. [6]. It is important to understand that there are two jurisdictions that exist in the U.S.; namely, federal and state. FERC is a federal entity and does not have the power to regulate state matters. NEPA specifically retains the states’ right to regulate retail wheeling. The state utility commissions have the jurisdiction to make sure that the electric monopolies in their states are run for the benefit of the citizens of that state. They can accomplish this by controlling the rate of return which utilities earn and also by dictating whether a utility’s investment is prudent or unwise. [3].

NEPA is no exception from the rule of red-tape and confusion which usually comes from Washington. Like most legislation, NEPA is written in global terms and implementation is left to the interpretation of the affected administrative agencies such as FERC and the state Public Service Commissions [1]. Ultimately, however, the interpretation resides in the courts and no one can predict whether TOA and all the other aspects of the Act will benefit or hurt utilities and their customers with respect to reliability and the pricing of electric energy.

It is, without a doubt, that California’s Public Utility Commission is on the forefront of seeing what can be done with the new found possibilities of a competitive power market. With a set of proposals released in April 1993, the California commission opened its networks to unprecedented competition in hopes of tying rate structures in with management-performance criterion [7]. The heart of the proposal is that of retail wheeling (a; opposed to “bulk” or wholesale wheeling). Retail wheeling (direct access) means that customers would be permitted to choose their own electricity suppliers. Not only does the California proposal include large commercial and industrial customers but also the individual residential customer. [7]. Recall, that NEPA was written with regard to transmission access, but transmission access can easily be seen to preclude retail wheeling
[1], which was left up to the states to regulate. In addition to California's proposal, Michigan is another state that is taking advantage of NEPA. Both of these states will be discussed in the next section.

**W.3 Wheeling:**

So far, several pages have been spent discussing what the major pieces of legislation concerning electric utilities has meant, does mean, and will mean. The term wheeling (both wholesale and retail) was mentioned on several occasions and especially in regard to NEPA. Wheeling is the heart of the operational and economic issues of TOA and thus deserves a separate treatment. Figure IV.2 is from Disbrow [1], and serves to complement the discussion on wheeling. Arguably, wheeling is the most important issue of NEPA.

In this description of wheeling, let the reader assume a 100 MW EWG desires to locate in utility A's service area and sell to utility B on the basis that utility A will supply transmission. Under NEPA, after the EWG applies for access, utility A has 60 days to determine the availability and pricing of the transmission. Example 1 of Figure IV.2 shows a 'best-case" scenario. Here, long term transmission capacity is available so, all that remains is for utility A to determine the matter of pricing. Prior to NEPA, bilateral agreements were used to determine the pricing between adjoining utilities based on embedded costs that are subject to change over time. With the EWG in place, though, this plan can not work. Other factors come into play in the pricing. Things such as control area services, losses on the transmission system, lost opportunity costs (i.e., the loss of a transmitting utility's ability to sell it's own power because line loadings are too high due to third party transactions), generating reserve, etc. The combination of all these costs could well exceed the bare embedded costs of the transmission facilities alone. This increased cost could easily destroy the EWGs competitive prices and they would subsequently protest to FERC. FERC would then, if recent cases are indicative, base the pricing on either embedded or incremental construction costs. Therefore a utility may or may not recover all of its costs.
Figure IV.2 How Power Wheeling Works [1]
Example 2 of Figure IV.2 shows the case when Utility A's transmission system can not adequately handle the proposed transaction. This may be because the extra loading may violate the utility's reliability standards or jeopardize the transmission system security. In this case, even though the utility protests the request for access based on lack of transmission capability, FERC can still order access be allowed. If this happens, the reliability of the system could be greatly decreased or FERC could order utility A to construct new transmission. The amount of time and capital outlay for new construction can be enormous, though. For instance, the last 765 kv line that American Electric Power Company constructed took almost 12 years to complete [1]. Also, one always runs into the typical environmental, emf, and "hot in my backyard" problems with construction. So, who pays for the added cost? If utility A adds a 2000 MW line so that the EWGs transaction can be supported, does the EWG only pay 1/20th of the cost? The state commission won't allow the cost to be passed on to the native load unless proof that the construction was in the best interest of the state can be shown.

The 3rd example in Figure IV.2 is that of the so-called stranded investment. In this case, suppose that a municipality within utility A's area is the proposed customer of the EWG. Here, the EWG is selling to a wholesale customer of utility A. Supposing that the municipality chooses not to purchase from utility A as it had in the past, but instead chooses to buy power from the EWG. Utility A must still provide voltage and reactive power support and backup generation when the EWG is on either a forced or scheduled outage. Once again, the question of losses is prevalent here. Had the seller been another utility, the losses would be a part of the contract obligations. The stranded investment comes from the fact that utility A had previously constructed generating facilities to supply the municipality. Now, in the presence of the EWG, the municipality neither uses nor pays for these facilities unless those costs are included in the transmission pricing. Thus the costs are spread out over the remaining native load which may or may not have need for those specific facilities.
Of particular concern, in reference to stranded investments, are utilities with nuclear facilities. These facilities are very costly and often lead to high utility rates for the customers who are served by the nuclear plant. These customers would benefit the most from wheeling by leaving their native system and purchasing from an EWG. There is no device in place to deal with this issue. It is not even clear if this problem falls under the jurisdiction of FERC or that of the state commissions. [3].

Example 4 continues, in a way, that of the stranded investment. In this scenario, the EWG finds a better transaction and thus discontinues service at the end of the fixed term with the municipality to sell its power elsewhere. Under the law, utility A is obligated to serve in exchange for its franchise area. Thus, even if there is a term contract with a customer, a utility can not terminate service even after the term. So, when the EWGs term agreement with the municipality expires, is utility A obligated to take the “prodigal” back. If the answer is that utility A must take back the municipality on demand, then planning processes become extremely complex. And from the municipalities standpoint, how is of long-term service assured and what are the responsibilities of the original and secondary suppliers? [1].

Although NEPA does not explicitly give rise to retail wheeling, as previously discussed, it does allow for the states to rule in that area. NEPA does, however, prohibit sham operations where a new wholesale purchasing entity is formed specifically for purchase and redistribution of energy to a utility’s native load. [1], [3]. According to [3] and [7], things at the state level in both Michigan and California., may be moving significantly faster than anticipated to try out the new legislation.

The Michigan Public Service Commission (PSC) has ordered a limited experiment for 5 years to test the viability of retail wheeling. In this experiment, customers of either Detroit Edison or Consumers Power with a demand of more than 5 MW can choose to purchase between 2 and 10 MW from other sources. No more than 90 MW of load for Detroit Edison and 60 MW for Consumers Power is to be affected by the experiment. This experiment hopes to define how retail wheeling will work. [3].
IV.10

The proposal issued by the California Public Utility Commission (CPUC) is even more significant [3]. The proposal claims that regulatory policy is “1) out of step and often in conflict with a changing, more competitive industry; 2) offers the utility at best weak incentives to operate and invest efficiently; 3) is composed of numerous, costly, and administratively burdensome proceedings; and, 4) creates unnecessary barriers to, and therefore threatens the quality of, public participation.” [7]. Recall that the California economy is suffering and the cost of doing business in California is much higher than in neighboring states. Many businesses are relocating and there is a push on the state government to encourage businesses to stay and new ones to start. [3].

The preamble to the CUPC’s proposal stated that it was ‘Single-minded in its objective — to lower the cost of electric service to California’s residential and business consumers without sacrificing the utility’s financial integrity.’” The CUPC’s plan is a phased introduction of retail wheeling by introducing “direct access to generation suppliers, marketers, brokers, and other service providers in the competitive marketplace for energy services.” There are three phases: Phase one takes affect in 1996 and allows customers who take service at 50kV or higher to shop for more competitive electrical service; phase two takes affect in 1998 and will effect most commercial customers; phase three is implemented in 2002 and will carry this option to all customers. [3],[7].

IV.4 Economic Issues

As was previously mentioned, the issue of economics can be denoted as one of the two major divisions of the open access experience; the other being issues of operation. Currently, in the U.S., the electrical system as it exists today is valued at 600 billion dollars with the equity stake of the shareholders in the investor-owned utilities being valued at approximately 200 billion dollars [3]. The main concern here, is that investments that were sound under the regulated monopolies could well prove to be poor investments in a competitive market. The two main financial issues that must be considered with
regard to OA are as follows: (1) reimbursing utilities for the costs associated with wheeling, and (2) the recovery of the stranded-investments mentioned earlier. [3],[7].

What is to be paid for transmission services is related to how the business is viewed [2]. In the new competitive market, the business must provide transmission service based on the standards of quality, reliability, security, and sufficient transmission capability at all times. These standards dictate what investments should be made and thus require that clear specifications and agreements be reached by the parties involved. Economic theory contends that the social optimum is achieved when, in an economic system, the goods and services are priced at marginal costs and installations are economically adapted so that they produce a given quantity at a minimum cost [2]. However, marginal pricing does not finance the system operation and development, as marginal costs are less than average costs. In addition, a simple price tag based on average cost of service does not provide economic incentives for efficient operation of the transmission business. As one can see, the problem of pricing is a complex one and will be addressed further below.

Conroy and Murray [2], break the evaluation of the cost of wheeling into three main issues; technical issues, cost component, and pricing methods. The technical issues arise from the complexity of the actual power flow path in a utility and the associated costs. The cost component is the idea that the actual cost to a utility for a wheeling transaction needs to be established before a price can be set. Finally, depending on the way costs are evaluated, several different approaches to pricing wheeling contracts may be used.

The technical issues are intimate with the economic issues of wheeling in that they affect the pricing approach for wheeling. The operational costs associated here are those of losses (i.e., $I^2R$ losses which are path dependent), voltage control and reactive power costs (the wheeling utility must ensure voltages stay within specified limits as additional power flowing through a system can affect voltage control), and security margins (they may be decreased due to increased power flow). The utility that is wheeling the power
with either absorb costs due to the wheeling or will establish specific actions to relieve the effects. It is not an easy task to separate the costs and proportion between the wheeling transactions and the normal operation of the system.

Conroy and Murray [3] also break down the cost component into several subcategories. The first is operating costs that a utility incurs during a wheeling transaction. The basic principal here is that prior to the transaction, the utility was operating in the most efficient manner possible via optimum power flow analysis and the most economical mix of generation. However, when the transaction occurs, this mix changes due to things such as transmission constraints and bus voltage limits. Thus, the cost to the utility changes, either positive or negative. Second, the utility may either gain or lose opportunity costs. That is, the ability or inability to import cheaper power or sell power wholesale because of the difference in flow that is in the system during the transaction. Third are the so-called reinforcement costs which refer to system expansions or changes that are needed to allow the wheeling transactions. Last are the embedded costs; these are the costs associated with the use of the existing systems. This is not an increased cost due to the transaction, but merely a sharing of the cost with the EWG for the existing system. Two terms often used to describe the above are short-run incremental cost (SRIC) and Long-run incremental cost (LRIC). SRIC refers to operating and opportunity costs and LRIC refers to operating, opportunity, and reinforcement costs. Once again, this subject of costs is prone to debate.

Finally, as a closing point to the economic issues, one must discuss methods of pricing. There has been much work done on evaluating rate structures and pricing basis, yet the author was unable to find any definitive works on the topic. However, there are many papers which address the issue of wheeling and pricing based on various methods. The overall thrust of this technical report is that of Real Time Pricing (RTP), there has yet to be much published work done on the application of RTP to NUGs. For further depth of the theory behind determining wheeling rates, the reader is referred to [8], [9], and [10].
Conroy and Murray [3] mention the two most common pricing methods that are now used to negotiate wheeling arrangements between utilities while Pérez-Arriaga, et al. [2], mention two additional schemes. The two most common are the contract path and postage stamp (rolled-in embedded costs) methods. The contract path allocation assumes a reasonable path is chosen and total costs of the path are allocated in proportion to use or other measures. The postage stamp method assumes that the network in used by everybody connected to it and costs must be allocated based on simple measures (e.g., total energy injection, peak power demand). The rate is based on the embedded cost of the whole system, irrespective of source and load locations. In addition, the incremental cost allocation method determines the difference of costs between situations with and without third party use. Finally, the megawatt mile method determines the changes in network flows due to the transaction and calculates the resultant product MW times mileage.

It should be noted that all of these methods contain some arbitrary assumptions that impact in what situations they may be applied. The best example being the near impossibility of determining a “reasonable path” in a system with many interconnections and generators [2]. One final note; under NEPA, FERC is permitted to order utilities to wheel power when it is in the best interest of the public. As stated before, it is the intent of NEPA to encourage a competitive market place in the electric power industry. However, FERC policy currently has only two situations which it addresses on pricing. They are as follows [3]:

- When the grid has been expanded to accommodate the increased capacity, the utility is allowed to recover either the embedded cost or the expansion cost.
- When the grid is not expanded and is therefore constrained, the utility can charge the higher of the embedded costs or legitimate opportunity costs. These are defined as costs that may be encountered in the transmission capacity to be utilized by the
wheeling utility itself to realize economy sales or purchases, which would have resulted in lowering of the rates to the utility's native load customers.

**IV,5 Operational Issues**

Regardless of the form that TOA takes, power system control is required to turn the policies into practice. The focus of TOA can be viewed in time frames (i.e., before the fact, real-time, and after the fact). Before the fact considerations uses the current practice of advanced resource and fuel scheduling to meet the forecasted load demand for the week ahead, however the analysis must also include demands of the TOA participants and the need to schedule new resources. Therefore, the operators are in need of additional information such as planned outages and deratings of transmission facilities, transmission usage reservation, and prioritization policies at least a week in advance. Operators will have to consider brokering of quoted purchases and sales over a much wider area, transmission capacity, path assignments with security allotments, parallel paths, and loss allocation. [2].

With real-time considerations, operators must be responsive to load demands and be prepared to respond quickly to unexpected events. TOA introduces a new dimension to power system operation and security assessment -- transmission system control. This control implies the use of Flexible AC Transmission Systems (FACTS), system stability and security constraint monitoring, and protective relaying coordination consistent with transmission control among other things. [2].

Once again, TOA complicates the issues, even of after the fact cost analysis. Cost reconstruction will be significantly affected by the TOA policies implemented. Settlements will require new analytical tools to resolve the payment issues. [2].

The operating point of a system is dependent on the system's topology (which is usually defined by the passive components) and is defined by the load flow (LF) solution or the optimal load flow (OPF) solution [6]. The introduction of an EWG into a system...
changes the system topology and introduces a new active component to the network which impacts the whole of the utility’s operational strategies. Thus, the location of an EWG will have a significant impact on the operation and security of a system. Prior to connection, a transmitting network has an already established load flow for real and reactive power in each transmission line that is based on existing generator bus voltage, reactive power generation, loadings, transformer and phase shifter tap settings, and the location and setting of the reactive power compensation devices. When an EWG is connected to the system, the direction of the proposed wheeling of real power is determined by the locations of the EWG and it’s proposed load. On the affected transmission lines, wheeled power may be in the same direction or in the opposite direction to the prevailing flow. If the wheeling flows are in the opposite direction, one can expect a decrease in line losses, where as if they are in the same direction one can expect an increase in losses and network loading. Figure IV.3 shows the Ward and Hale 6 bus system for two scenarios which were performed by Ouyang and Deep [6] to study the effects of placement of the EWG. Note that the load flow results for the base case (no EWG) are indicated as (0) and the results of scenario one and scenario two are indicated by (1) and (2), respectively. The statement of the example is presented here from [6]:

This example consists of two wheeling scenarios on the Ward and Hale 6 bus system. Scenario one represents the addition of a 15 MW EWG generator connected to Bus 3 and a designated 15 MW, 0.9 power factor EWG load represented by a load increase at Bus 5. Scenario two addresses the addition of a 15 MW EWG generator which is placed on Bus 6 and an associated load connected to Bus 2. The study of the load flow of the base case indicates that the prevailing power flows along transmission line 25 (from
bus 2 to btr 5) and 35 are directed toward Btis 5. The flow direction along line 26 in toward Btis 6.

The total losses of each scenario are summed up in Table IV.1 below.

Table IV.1 Summary of Total Losses in Load Flow Studies

<table>
<thead>
<tr>
<th>Scenario</th>
<th>MW</th>
<th>MVA</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>11.65</td>
<td>36.97</td>
</tr>
<tr>
<td>1</td>
<td>13.76</td>
<td>46.06</td>
</tr>
<tr>
<td>2</td>
<td>8.74</td>
<td>29.79</td>
</tr>
</tbody>
</table>
Since the prevailing flow of power (in the base case) is from Bus 2 to Bus 6, one would expect that network losses would be reduced in scenario 2. It is noted from Figure IV.3 that the results of scenario 1 are just the opposite. In scenario one, the losses increased by 2.11 MW and 9.09 MVAR from the base case. In scenario 2, however, losses were decreased by 2.91 MW and 7.18 MVAR. Thus, the security in scenario 2 is increased because the loading on line 62 is decreased. The wheeling of power in scenario one caused the 15 MVA transformer (35) to be overloaded to 19.3 MVA.

Ouyang and Deeb [6] go on to present two more cases which are of interest in operational issues. In the second case, a 15 MW EWG is connected to Bus 6 and its corresponding 0.8 pf load at Bus 5 (a “cross” between scenarios 1 and 2 of case one). It is found that decreasing the power factor of the EWG unit from 1.0 to 0.72 in this case (without any other adjustment of network controls) reduces the overall real power loss by 11% (1.35 MW). This indicates that EWGs should be operating at a power factor in favor of overall network optimization within its thermal limitations. Such optimal operating conditions must be dictated by the transmitting utility through SCADA/EMS controls.

Ouyang and Deeb’s third case investigates the effectiveness of adjusting network controls to accommodate a wheeling transaction. Recall that in scenario 1 of case 1 that the 15 MVA transformer (35) was overloaded as a result of the placement of the EWG. The authors state that the power can flow to the EWG load from two paths. Through the transformer, as in scenario 1, or through a transmission line from Bus 2, which is assumed to have the necessary capacity. To achieve this, a phase shifting transformer is placed in line 34 and the secondary tap on transformer 35 is adjusted from 2.5% boost to 10% boost, thus reducing the amount of reactive power flow through the transformer. By adjusting the phase shifting transformer angle to -13° the real power flow on line 34 is greatly reduced to 0.07 MW from bus 3 to bus 4. The total power in the transformer is also reduced to 11.7 MW and 8.8 MVAR (14.7 MVA). The bus voltage at Bus 5 drops from 0.84 (in scenario 1, case 1) to 0.8 per unit. To bring Bus 5 voltage back up to initial
load, a required per unit voltage at bus 1 of 1.14 is needed. This is, of course, impractical; but does demonstrate the effect of voltage control.

**IV.6 Security Issues**

A final issue to be considered in light of NUGs and NEPA is that of the security of the power transmission system. This has been mentioned in passing in previous sections, but will now be expounded on somewhat further. Power system security is defined as the ability to supply the system load, without overloading branches and violating bus voltages under normal conditions and contingencies [6],[11]. Since an EWG is composed of generation and transmission links to the network, it will affect the security of the system either by outage or by operation. Thus, EMS systems will need to be incorporated with security analysis functions that are run at each cycle of EWG generation based on security regulations of the particular utility and the current contract with the EWG. As can be easily seen, this is not a trivial problem. Once again, Ouyang and Deeb [6], as well as McCalley [11] go into some depth on the analysis the security issue, and McCalley, in particular analyzes the costs associated with meeting system security criteria.

**IV.7 Summary**

This paper has covered current trends in the deregulation of the electric power industry due to NEPA. It has investigated economic, operational, and security issues that are related to the open access of transmission systems. It was found from the literature that although NEPA was passed to promote growth and competition in the electric power industry by providing consumers a choice of rates it has, in fact, caused more of a burden than a relief. This is mainly due to the fact that NEPA was written in very global terms without regard to engineering design and is thus open to interpretation by those agencies to which NEPA’s powers are given. Perhaps, however, NEPA will stimulate development of FACTS and other technologies which will in the long-run benefit both the consumer and the producer. On the other hand, NEPA may also be realized to have been a grand
mistake and will be ‘reformed’, just as NEPA was to be a reform to PURPA. Only time will tell. Until that time conies, engineers, economists, beauracrats, and politicians all have their work cut out for them.
Bibliography


CHAPTER V
Power Wheeling and Its Cost

V-1 Abstract

The wheeling cost is currently an area of research interest in light of the increased de-regulation in North America. This paper will address the issue of wheeling cost, with both short- and long-term models presented. Emphasis on the use of optimal power flow (OPF) to handle the short-term marginal cost model is introduced. Discussions are also presented on the topics of optimal multi-area wheeling, and reactive power wheeling.

Optimal multi-area wheeling addresses the question of how much energy should be transmitted through each wheeling path and what wheeling price should be paid. This is formulated as a nonlinear optimization program with linear constraints and solved by the gradient projection method.

Reactive wheeling is presented with the aid of AC power flow model. The ratio of wheeling rates between active and reactive flow shows the importance of the latter. The significance of this fact is viewed in light of the trade-off between paying for reactive wheeling and investing in compensating plants.

V-2 Introduction

Recent trends in the electric power utility industry have been toward the increased unbundling of services provided by the utilities. Power wheeling has attracted much attentions and become an increasingly popular topic.

Power wheeling is the phenomenon that can take place with multiple neighboring utilities when one system's transmission network is simply being used to transmit power from one neighbor to another. Since the automatic generation control (AGC) of the intermediate system will keep net interchange to a specific value regardless of the power being currently transmitted, the transmission losses incurred in the intermediate system will change, and the flow of energy within the intermediate system itself for its own users will change also. When the losses are increased, the intermediate system has to increase its generation level to compensate the losses, and thus an unfair burden is added onto the wheeling utility. For that reason, unless the transmission is part of the interchange agreement, the wheeling utility will often post a wheeling charge on its users -- the buyer or the seller or both.

As pointed out in [7], three-party power transactions are frequently made in the United States today, where utility B finds a seller, utility S, and makes arrangement with utility K to complete the wheeling. The transaction is actually done in a dual manner -- S sells to K and K sells to B.
Electric power utilities need to know the actual costs of providing separate services in order to make correct economic decisions on the various types of services they should promote or curtail while at the same time fulfilling their service obligations.

Utilities also need to know such costs in order to make correct economic and engineering decisions on upgrading and expanding their generation, transmission and distribution facilities.

As FACTS devices become more widely incorporated, their optimal use becomes an issue of interest, especially in complex wheeling situations.

V-3 Wheeling definition and background

As defined by the Office of Technology Assessment of the United States Congress, wheeling is the transmission of electric power from a seller to a buyer, through transmission network owned by a third party. The intermediate transmission network can sometimes include several transmission systems, each of which wheels certain amount of power from the buyer to the seller. Each wheeling utility is termed as a wheel.

When the contracted energy flow enters and leaves the wheeling utility, the flows throughout the wheeling utility's network will change. The transmission losses incurred in the wheeling utility will change. Wheeling rates are the prices it charges for use of its network, which determine payments by the buyers or sellers, or both, to the wheeling utility to compensate it for the generation and network costs incurred.

There are four major types of wheeling depending on the relationships between the wheeling utility and the buyer-seller parties[5].

- **utility to utility**: this is usually the case of area to area wheeling.

- **utility to private user or requirements customer**: the former is usually the case of area to bus wheeling, while the latter is usually the case of area to area wheeling, unless the requirements customer is small enough to be fed only at one bus, and thus becomes area to bus wheeling.

- **private generator to utility**: bus to area wheeling

- **private generator to private generator**: bus to bus wheeling.

Wheeling power may either increase or decrease transmission losses depending on whether the power wheeled flows in the same direction as, or counter to, the native load on the wheeler's lines. Wheeling power on a heavily loaded line causes more energy loss.[5]

The cost of wheeling is a current high priority problem throughout the power industry for utilities, independent power producers, as well as regulators. The following three factors have led to the importance of the cost of wheeling problem:

1) enormous growth in transmission facilities at 230-kV and above since the 1960's.

2) cost differentials for electric energy between different but interconnected electric utilities.
3) high cost of new plant construction versus long term, off-system capacity purchase.

4) dramatic growth in non-utility generation (NUG) capacity, which includes Independent Power Producers (IPP) and cogenerators, due to the passage of the Public Utility Regulatory Act in 1978, and the subsequent introduction of competitive bidding for generation capacity and energy.

Wheeling is necessary and important for any NUG, unless the customer of a NUG is the utility itself to which it is directly connected.

V-4 Wheeling cost models

What types of costs are really involved, and how much each one is, when a utility wheels a certain amount of energy through its transmission network?

The question can be addressed from either a short-term or a long-term perspective, and thus factors to be considered in each case varies and results differ considerably. We will look at the short-term model first.

Short-Run Marginal Cost Model

The short-run marginal costs (SRMC) of wheeling are the costs of the last MWh of energy wheeled, which can be computed from the difference in the marginal costs of electricity at the entry and exit buses, that is, the difference in the spot prices of these buses. An extensive treatment on the theory underlying wheeling costs, using marginal cost pricing and related computations can be found in [1].

\[
SRMC\ of\ wheeling = \left( \frac{\partial f}{\partial MW_1} \right) - \left( \frac{\partial f}{\partial MW_2} \right)
\]

where:

- \( f_i \) = production cost rate at bus \( i \) in $/hour, \( i = 1,2 \)
- \( MW_i \) = MW injection at bus \( i \), \( i = 1,2 \)

And again, this is simply the equation of spot prices.

As mentioned earlier in this paper, if utility S and utility B decide to engage in a transaction involving \( W \) MWh of energy during hour \( t \), utility S increases its net scheduled interchange by \( W \) while utility B decreases its net scheduled interchange by \( W \). This changes the flows throughout the network, including the lines of utility \( K \). The specific flow changes are not under the direct control of any of the utilities. Kirchoff's laws and the changed generation patterns determine what happens. Some of this \( W \) MWh of energy will flow through utility \( K \) independent of whether or not utility \( K \) gives permission. The sum of all tie line flows into and out of utility \( K \) do not change. However, utility \( K \)'s costs are affected because of changes in its internal losses, which further affects its generation costs, and possible impacts on line flow and voltage magnitude constraints. Further, the costs of the capital utility \( K \) has invested in its transmission system can not be ignored.
As demand patterns, generator availability, and transmission availability vary over a day and longer periods, the utilities' dispatching patterns and costs vary. This gives rise to time-varying spot prices, which capture all relevant economic and engineering information. Because of losses and system security constraints, it is understood that 1 MWh of energy has different values at different time and different buses of the network. Since wheeling is analogous to buying energy at one set of buses and selling it at another set of buses, these spot price differences determine the cost of wheeling.

However, a sound costing method should further incorporate embedded costs, should take into consideration system security, Var requirements and voltage profile. An analytical tool well equipped to address this issue is the Optimal Power Flow (OPF) program.

Optimal Power Flow programs can be used to effectively determine the cost and viability of NUG options or wheeling contracts. OPFs model both the generation and transmission systems and for a particular snap-shot in time can yield extremely accurate information on such quantities as short-term marginal wheeling costs.

Contrast to the ordinary power flows which calculate system parameters such as voltages at load buses corresponding to a specified setting of variables such as generator power output, OPFs attempt to find the best possible setting for a list of control variables such that a desired objective is met. The control variables include generator bus voltages, transformer and phase shifter settings, real power at generator buses, addition of VArS and shedding load.

Such OPF also model system security constraints which set the optimal control setting such that the system can survive a specified list of contingencies.

A hypothetical Wheeling Case
As reported in [6], the IEEE 30-bus test system, as shown in Figure [V-1] below, is illustrated here for a hypothetical wheeling case. There are 3 transmission areas 1, 5, and 12 in the system, which is being centrally dispatched. The NUG on bus 14 of area 5 wishes to sell 50 MW of firm power to a process industry located at bus 27 of area 12. The contract path for this power transfer is through areas 5 and 12. The following system-wide and line flow constraints are specified:

<table>
<thead>
<tr>
<th>system-wide constraint</th>
<th>voltage limits: 0.95 pu to 1.05 pu normal, 0.9 pu to 1.1 pu emergency</th>
</tr>
</thead>
<tbody>
<tr>
<td>lineflow constraints</td>
<td>line 15 to 23: 15 MVA normal, 20 MVA emergency</td>
</tr>
<tr>
<td></td>
<td>line 22 to 24: 11 MVA normal, 15 MVA emergency</td>
</tr>
<tr>
<td></td>
<td>line 6 to 28: 40 MVA normal, 45 MVA emergency</td>
</tr>
</tbody>
</table>

The following contingency constraints were defined to maintain system security with the wheeling contract:

V-4
contingency constraints

generator on bus 8 out of service
line from bus 19 to bus 20 out of service
line from bus 23 to bus 24 out of service

With the above case defined, we can look at several important aspects of this wheeling contract, which in the end, will shape the cost of the overall cost of the contract. They include transfer limits with \( \text{VAR} \) requirements and loss allocation.

Figure[V-1] IEEE 30-Bus Test System for Hypothetical Case [6]
1. **transfer limits with VAr requirements:**

To determine the transfer limits of a given hour of a day, a single run security constrained OPF is all that is needed. The result takes into consideration voltage and line flow limits, tap and VAr compensation limits, phase shifter limits and security limits.

Transfer capability can often be increased by adding VAr at strategic locations of the system. VAr size and sites may be determined by an OPF. System security is also a major factor in the determination of transfer capability. As expected, an ordinary OPF run without security constraints may seriously overestimate the maximum transfer limits. **Table[V-2]** shows the result of several OPF runs and shows the effect of VAr compensation in the transmission system. It also shows that security constraints are of paramount importance in establishing the maximum transfer limit. For example, the system can wheel 44.1 MW without security constraints (and without VAr compensation). But when system security constraints are applied, only 34.4 MW of power can be wheeled (again, without VAr compensation).

<table>
<thead>
<tr>
<th>Case Description</th>
<th>NUC Generation MW</th>
<th>NUC Load MW</th>
<th>Added Shunt MVAr</th>
<th>Wheeling Losses MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three Contingencies</td>
<td>34.4</td>
<td>30.9</td>
<td>56</td>
<td>3.5</td>
</tr>
<tr>
<td>No Contingencies</td>
<td>44.1</td>
<td>40.0</td>
<td>23</td>
<td>4.1</td>
</tr>
<tr>
<td>Three Contingencies</td>
<td>24.1</td>
<td>21.8</td>
<td>0</td>
<td>23</td>
</tr>
<tr>
<td>(No MVArs)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Contingencies</td>
<td>36.2</td>
<td>32.5</td>
<td>0</td>
<td>3.7</td>
</tr>
<tr>
<td>(No MVArs)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table[V-2]** Maximum Transfer Limits and Shunt VAr Requirements [6]

2. **Loss Allocation**

The wheeling losses in **Table[V-2]** represent the additional transmission losses due to the wheeling contract.

The question of how to allocate the cost of the increased losses due to wheeling becomes a complicated one if the wheeling requires the utility to re-dispatch generation to accommodate the wheeling. One solution is to use OPF to compute an economic dispatch with and without the wheeling arrangement. The difference apparently points to the impact due to wheeling, and a cost can be associated with it. In this case, if multiple wheeling contracts are being considered, several program runs must be made with the contracts grouped by priority.

An example on our 30-bus system can demonstrate the above theory. The results are shown in **Table[V-3]**. The OPF is run for dispatch with and without wheeling, observing all the constraints mentioned earlier. The base case represents the that without wheeling. Again the cases with and without contingency considerations are shown and compared against.
The assumption we are making here is that the network can accommodate the 50 MW being supplied by the NUG, provided that the 3 utilities (area 1, 5, and 12) re-dispatch their generation.

Table [V-3]  Loss Allocation when Utilities Re-dispatch Generation [6]

As shown in Table [V-3], for the base case, no additional VAr's were needed to satisfy the contingency conditions, implying that the system was designed to survive these contingencies. When the wheeling problem was considered without the contingencies, the OPF program found that there was a substantial increase in the losses and the required compensation, but the desired 50-MW of power could still be delivered at bus 27. The situation is different when the contingencies are considered. Only 46.1-MW could be delivered at the load because of the MVA flow limits on the line from bus 15 to 23. In addition, the compensation requirements and the losses were significantly higher. For example, to transfer close to 50-MW of power, the added shunt compensation is as high as 950-MVAr, which will almost certainly make this wheeling contract very uneconomical.

Table [V-4]  Area Losses and Generation (MW) [6]
From the change in total losses, it is relatively easy to determine the energy cost of transmission for the NUG. This is computed by taking the difference between total losses before and after wheeling. If contingencies are not monitored, the NUG would be liable for 7.50-MW (= (1.90 + 6.17 + 2.63) - (1.83 + 0.76 + 0.58)) of losses. If contingencies are considered, the NUG would be liable for 16.09-MW (= (6.36 + 11.69 + 1.21) - (1.83 + 0.76 + 0.58)) of losses.

Table[V-4] compares the losses and generation of MW's and MVAR's for each area before and after wheeling. Such a breakdown in losses and generation is necessary to determine a basis for compensating individual utilities for the increased transmission losses due to wheeling. Mechanisms similar to "split-savings" can be used to allocate costs when utilities re-dispatch to accommodate wheeling contracts.

3. cost of wheeling using short run marginal cost model

At this stage, the marginal costs at all buses are readily available from OPFs. This is because OPF algorithms inherently use partial derivatives to minimize the objective function. If the objective function is production cost, the partial derivatives of the cost with respect to real power can be easily obtained for each bus in the system. The marginal cost of wheeling power between two buses is simply the difference between their partial derivatives.

In general, power should be wheeled between buses which have low marginal wheeling cost. Non-zero marginal wheeling costs arise due to losses or power flow constraints. As we understand, if we can have a perfect (unrealistic) dispatch, the incremental cost at each bus will be the same, as the Equal Incremental Cost rule will determine, and thus the cost of wheeling will be zero.

The marginal costs of wheeling power originating at bus 14 of the IEEE test system for these cases is presented in Table[V-5]. As expected, the case with no line flow limits has the lowest marginal wheeling costs. These costs increase dramatically for certain buses when there are flow or security constraints. In the cases presented in Table[V-5], this occurs when power is being wheeled beyond the transfer limits of the network capability and very high cost emergency power purchases from neighboring utilities are used to accommodate the wheeling. When security as well as line constraints are observed, the marginal cost of wheeling increases for most buses. In general, as we may expect, the more constrained the system, the more costly it is to wheel power between buses. Table[V-5] also shows some instances where marginal wheeling costs decrease as a result of recognizing line limits and security constraints. However, such decreases are usually off-set by large increase in marginal wheeling costs elsewhere in the system.

We should note that adding new lines or installing VAr's may be implemented to remove flow constraints and thus lower the marginal cost of wheeling. OPF program run may be used to quantify the benefits of such capital expenditures to support wheeling transactions.

In addition, as we noted earlier, the marginal cost of wheeling varies from hour to hour, corresponding to loading conditions and the state of the system. To form a basis for
the calculation of wheeling charges, marginal cost of wheeling needs to be evaluated over an extended period of time.

<table>
<thead>
<tr>
<th>Bus Number</th>
<th>Case I Line Limits + Security</th>
<th>Case II Line Limits No Security</th>
<th>Case III No Security</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Constraints</td>
<td>Cost $/MW</td>
<td>Constraints</td>
</tr>
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<tr>
<td>30</td>
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<td>410.49</td>
<td>10.36</td>
</tr>
</tbody>
</table>

Table[V-5] Short Term Absolute Marginal Costs of Wheeling for the: 30 Bus Case for Power Originating from Bus 14 [6]

In conclusion, Optimal Power Flows are a versatile tool for evaluation of NUG or wheeling options for utility system planning. OPFs provide vital information regarding:

- **Voltage Support**: OPFs can calculate the change in system component settings to maintain the desired voltage profile. This can be done in one single OPF run.

- **VAr Requirements**: OPFs can calculate the best sites and amount for shunt compensation required to accommodate a NUG or wheeling contract. The VAr requirements can be found by a single run of OPF.
- System Security: OPFs ensure that system security constraints are met while accommodating a NUG or wheeling contract.
- System Losses: OPFs quantify the effect of a new NUG or wheeling contract on system losses, and thus information be used to minimize losses.
- Short Term Marginal Cost of Wheeling: can be determined and form a starting point in the calculation of wheeling cost.

A number of embedded as well as newly developed long-run incremental methods determining the costs of firm wheeling, and to present methodologies that allocate the wheeling costs in the case of multiple wheels present in the system is presented in [1].

**Embedded Cost Models**

Embedded cost of wheeling methods, used throughout the utility industry, allocated the embedded capital costs and the average annual operation (not production) and maintenance costs of existing facilities to a particular wheel; these facilities include transmission, subtransmission, and substation facilities. Happ has given a detailed treatment on all the methods as well as their algorithms in [2].

There are 4 types of embedded methods:
- Rolled-in-embedded method
- Contract path method
- Boundary flow method
- Line-by-line method

**Rolled-In-Embedded Method**

This method assumes that the entire transmission system is used in wheeling, regardless of the actual transmission facilities that carry the wheel. The cost of wheeling as determined by this method is independent of the distance of the wheel, which is the reason that the method is also known as the Postage Stamp Method. The embedded capital costs correspondingly reflect the entire transmission system.

**Contract Path Method**

This method is based upon the assumption that the wheel is confined to flow along a specified electrically continuous path through the wheeling company’s transmission system. Changes in flows in facilities which are not along the identified path are ignored. Thus this method is limited to those facilities which lie along this assumed path.

**Boundary Flow Method**

This method incorporates changes in MW boundary flows of the wheeling company due to a wheel, on either a line basis or on a net interchange basis, into the cost of wheeling. Two power flows, executed successively for every year with and without each wheel, yield the changes in either individual boundary line or net interchange MW
flows. The load level represented in the power flows can be at peak load or any other appropriate load.

**Line-by-line Method**

This method considers changes in MW flows due to the wheel in all transmission lines of the wheeling company, and the line lengths in miles. Two power flows executed with and without the wheel yield the changes in MW flows in all transmission lines.

In general, the first two methods are considered to be traditional and widely used in power industry. Neither of them require power flow executions and associated studies to identify the companies, and in the case of the contract path method, the transmission lines which are the principal carriers of the wheel. Simplicity is their advantage.

In the absence of sufficient system studies, no identifications as to the principal transmission lines or companies responsible for the wheeling can be a serious limitation. The latter two embedded cost methods require the execution of power flow, and thus have the potential to improve upon the limitations for the first two methods.

There are 2 limitations common to all 4 embedded cost methods:
1) The methods consider only the costs of existing transmission facilities.
2) The methods do not consider changes in production costs as a result of required changes in dispatch and or unit commitment due to the presence of the wheel.

Other cost factors may exist which contribute to the cost of wheeling. For example, the economic purchases or sales of power which have to be curtailed to accommodate the wheel due to transmission limits.

**Long Run Incremental Cost (LRIC) Models**

Long run incremental transmission costs for wheeling account for:

a) the investment costs for reinforcement to accommodate the wheel, or credit for delaying or avoiding reinforcements, and
b) the charge in operating costs and incremental operation and maintenance costs incurred due to the wheel.

There are currently two models for the LRIC methodologies: standard long run incremental cost (SLRIC) methodology and long run fully incremental cost (LRFIC) methodology.

The standard long run incremental cost method uses traditional system planning approaches to determine reinforcements that are required, and corresponding investment schedules with and without each wheel, throughout the study period. If more than one wheel is present in the study period, the cost of each reinforcement and the change in operating costs, have to be accurately allocated to each wheel.

The long run fully incremental cost method does not allow excess transmission capacity to be used by a wheel but forces a reinforcement along the path of the wheel to accommodate it; if more than one wheel is present in the study period, a reinforcement is required for each separate wheel. [2]
Multi-area wheeling is a real-world practical concern, because wheeling from a seller to a buyer involves power flow through several intermediate networks. How much power should be wheeled through each path, what wheeling charges should be applied to each such transaction and how these decisions can be made optimal? FACTS devices, which are now made more and more available, should be controlled to achieve these optimal transfers through each separate path.

Consider an interconnected system with multiple intermediate wheeling utilities and multiple seller-buyer couples. A simplified version of this set up is shown in Figure[V-6] with 3 intermediate wheeling utilities $W_1, W_2, \text{ and } W_3$, and one buyer and seller pair (S-B). There are 7 inter-utility wheeling paths, given by the directed path $k_1$ through $k_7$.

Suppose that the energy to be transported through each path is set arbitrarily, then the computation of wheeling rates for each path can be obtained from the solution of an economic dispatch problem using OPF program. To decide the optimal power flow on each path, the power flows can be set as variables and the wheeling rates can be used to improve the initial set values. The total operating costs have to be minimized considering the topological structure of multi-wheeling areas and the feasible region of wheeling power flow. The topological relation can be reflected in the following matrix equation. The assumptions made for the relation are:

1. power inflow is given a positive sign and power outflow is given a negative sign; and
2. we are only concerned with the sale of unit power from S to B.

Each row column multiplication represents one power balance equation for a particular utility (there are a total of 5 utilities in this example).
This turns out to be a nonlinear program with linear constraints. The gradient of the objective function turned out to be the marginal cost of electricity at the buses of power entrance and exit, which can be found from the OPF solution. Since the constraints are linear this problem is solved by a gradient projection method. Interested readers can consult [3] for details and example in the solution of this problem.

V-6 Wheeling concerns for reactive power

Reactive energy flows can be important as they affect both real line losses and voltage magnitudes, and therefore impact on the total operating cost of the system. As power system margins are reduced because of emphasis on the greater use of generation and transmission, power systems are operated much closer to their technical limits. Thus the marginal cost of reactive power, and the effect of reactive power on the marginal cost of real power should be included in the overall considerations of wheeling rates, especially when an average rather than a real time wheeling rate is needed, since the establishment of wheeling rates need to allow for modifications in reactive resources. For example, a capacitor installation funded by the seller-buyer of the wheel may be cost-effective compared to simply accepting the "as is" wheeling rate.

Real time prices for reactive power can provide information to both users and dispatchers of electricity about the cost and value of reactive power usage, flow and sources. In general, although the marginal cost of reactive power generation is far smaller than for real power, the important point is that the differences between the entry and exit buses for real and reactive power are comparable. Therefore in the computation of wheeling costs, reactive energy flow is not negligible.

If the wheeling rates of reactive power flow are to be considered, an AC model must be used. A modification of optimal power flow model, which allows for the spot price responsiveness of both real and reactive power demand, is used in [4] to analyze the wheeling rates of real and reactive power.

At first sight, if the production costs of reactive power are taken to be negligibly small, the pricing of reactive wheel may appear to depend primarily on its impact on transmission losses and on the changes in the wheelers production costs brought about by
the need to reschedule any of its own dispatch. However, when the system loading is very heavy, the flow of reactive power can push bus voltages, tap change transformer settings or circuit loading to their limits, or in an opposite orientation, can bring them off limits. The consequence of system constraint activation is not confined to reactive wheeling pricing only but also seriously affects real power pricing and wheeling.

It is concluded in [4] that:

- reactive power flow associated with a wheel affects costs because it impacts on losses, allowable operating ranges, and generating costs;
- that DC load flow model is inappropriate for determining wheeling rates because they ignore the effects of reactive power flow; an AC-OPF model must be used;
- that the potential error of ignoring reactive power in wheeling studies increase with the magnitude of the wheel and if the power factor of the wheel is adverse;
- reactive power wheeling charges, and the changes in real power wheeling charges brought about by reactive wheeling, provide a useful guideline of what savings can be made by installing reactive compensating equipment, and thus provide pertinent information in deciding an appropriate level of reactive plant investment.

V-7 Conclusions

A comprehensive review of the subject of power wheeling in light of wheeling cost models, optimization of multi-area wheeling and considerations for reactive power wheeling are presented in this paper.

It is concluded that short run marginal cost of wheeling can be effectively evaluated using the security constrained Optimal Power Flow program. Several embedded cost models and long run incremental cost models of wheeling were briefly introduced.

It is found that the optimization problem of multi-area wheeling is a nonlinear program with linear constraints and therefore can be solved by gradient projection method. Considerations on the topological structures of multiple wheels are expressed in a matrix form equation.

The evaluation of reactive energy flow shows that reactive power can affect both real line losses and system voltage profile. Thus its impact is both short- and long-term, and should not be neglected in calculating an averaged over time wheeling cost.
REFERENCES

Chapter VI
Calculation of Marginal (Incremental) Fuel Costs of a RTP Program

J. S. Lee

VI.1. Introduction

Since their early days electric utilities have been interested in rate design and other demand side management programs as a way to improve capacity utilization [9, page 88]. Open transmission access and competition have heated even more the interest in pricing strategies. RTP program design must be tailor made for each customer class according to the kind of service provided, because customer capability and willingness to response to prices are a prime aspect in this tariff. In the current electricity industry jargon, real-time pricing (RTP) is a kind of rate that allows the utility to determine a different electricity price for every hour of the day, every day, based on utility incremental costs [6] [7]. This paper analyzes an especial RTP design that aims large industrial users that own cogeneration facilities and it requires that the industrial customer inform back which quantity it is going to use. Since this program departs from the usual RTP calculation method, this paper develops an alternate method that best reflect the incremental cost caused by the adoption of this specific program.

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1 The RTP price schedules may also differentiate according to customer location. Customers located over different transmission or distribution lines may be charged different prices according to the load (and consequent losses) in the line during the period considered. Power literature criticizes nodal price implementation because of potential market power discretion [13] and perverse pricing of due to the interaction of power flows [12].
Recently real-time pricing has found a place as a marketing tool in a more competitive and liberal utility environment. Also, since neighbor utilities may use hourly power exchange transactions, to minimize fuel cost of the system, RTP is not only a demand side strategy, but also a supply option to customers willing to participate. If customer's response is in the same time frame of neighbor utilities, the local utility may become a power broker that can find the best energy alternative in the region[16]. Whatever the utility is in a regulated or competitive environment RTP can improve utility operation and capacity resource use.

The final price the utility will offer to the consumer will depend on contractual nuances between customer and utility, utility required return over fix costs and utility load profile. Nevertheless, the main variation source in RTP price determination is utility incremental fuel and operational costs. The objective of this paper is to propose a method to calculate real-time price of a program that offers a weekly price-quantity consumption schedule in one hour price intervals. The real-time price determination is based on the utility own incremental fuel cost of electricity and one hour power imported and exported from neighbor utilities. This paper will not discuss the contractual and structural that alter the final RTP. One may refer to [3], [2] and [8] for a discussion of these aspects.

VI.2. A price system that considers electricity supply and demand

RTP belongs to the incremental cost rate family, like of time of day (TOD) pricing rates, with which the utility industry has had long time experience. On time of day pricing, the utility may modify prices once a month or a year, to usually offer 2 different prices. A low price for electricity used during valley periods (for example, night time) and a high price for used during peak periods. Ideally difference between the two prices is the average difference in incremental production costs between the two levels of demand (valley and peak). RTP is a more intense implementation of TOD pricing, which allows a better approximation of the system cost conditions and recent changes in consumption patterns.

Supply factors refer to system resource status and load, such as commitment and output level of generating units, spinning reserve, reliability level, transmission and distribution line loads and neighbor or pool economic power transfer prices. Supply resources are usually used up in incremental order from the lowest to the highest marginal or incremental cost. In the short
run the utility wants to minimize in marginal fuel and outage costs while obtaining enough revenue to cover fixed costs. Fixed costs are supply factors related to long run capacity. Usually the state utility commission determines an amount each customer (or customer class) contribution to fix costs, when it defines rate class revenue requirements. RTP rates must also collect an exact revenue requirement to contribute to the system fix cost investment.

Some utilities classify RTP programs as demand side management programs (DSM), because of this need of understanding the customer and of their potential for increasing the utility ability to forecast and control system loads. The utility may use load control as a tool to improve capacity utilization, reliability and operational efficiency, and potentially postpone capacity expansion. RTP and other incremental rate strategies, nonetheless, allow the utility to increase load control signals to a broader base of customers and applications than traditional DSM programs. The reason for potentially larger participation is that incremental cost information conveyed in form of prices allows the customer to valuate his own alternative ways for conserving and using electricity. Besides incremental cost rates preserve customer choice and satisfaction, RTP as a tool of demand control is not perfect because of individual customer response variability to electricity prices. This statement makes clear that RTP is not the final answer for electric power control, but another instrument used to smooth operations and maximizes benefits to system resource users.

VI.2.1 Customer response to electricity prices

Demand factors have take a central consideration in RTP programs, since customer electricity service requirements, load characteristics and price responsiveness are key for RTP success. Customer requirements vary with customer class and usually include: power quality, service voltage, number of meters, load level, power factor and harmonic limitations. These requirements may affect fix (or capacity) or variable (or energy) costs or relative to marginal cost language, long or short run marginal costs. The utility may reduce outage costs and therefore reduce its RTP price, if the customer agrees with an interruptible RTP rate. Schwepe [14] called by as price-quantity transactions RTP programs that combine 24 price update and an interruptible contract. Note that in this kind of RTP the calculation of reserve requirements does not include the expected RTP participant demand.
In the regulated utility environment, customers are divided in classes according to the services they require (that is, voltage level, maximum peak demand, minimum energy consumption during a month, power quality, etc.). All customers in a rate class share the costs the utility incurs to provide the services. The costs associated to a rate class refer to the investment made in the past to serve its customers current and future demand, plus variable costs associated with energy consumed and rate class reliability requirements. Contractual nuances in a rate class may affect directly utility incremental fuel costs, in which case they must be considered in the calculation of RTP as marginal costs. For instance, contractual arrangements about power quality, such as, firm or interruptible contract, number of interruptions a year and notification time before interruptions may directly affect marginal fuel costing. Other contractual nuances may refer to fix cost investment that a customer class must repay because they were specifically or shared by the class, such as transmission and distribution equipment required. These repayments maybe collected as fix adders or multipliers in unit prices.

Customer division in rate classes does not necessarily indicate that customers in the same rate class have the same response to electricity price changes, i.e., common elasticity price elasticity. Nevertheless, we can assume that the responses of n customers in a rate class have the same effect of n identical representative class customers' responses. As electricity prices vary this representative customer will choose to consume different amounts of the electricity or, more precisely, electricity services. This quantity choice depends on the value the representative customer attributes to electricity services and the current cost to the customer of using some alternative good or service that replaces the electricity services. The value perception of electricity services that a single customer has may differ from one day to the next or over other periods of time. For example, an industrial customer may value more electricity services the larger number of orders received last week, or the larger the number of machines he foresees will be available in the next few hours. Hence the elasticity response of the same individual may change over time given some especial conditions. When this effects accumulate over a large number of customers the response variability is smaller unless the utility errs the forecast of factors that are common to all consumer class. E.g. all residential customers may require unforeseen extra heating during a day which temperature was lower than the utility forecast.

Besides own price elasticity the utility must be aware of other customers' input and output electricity cross price elasticities when forecasting customer behavior. Electricity cross
price elasticity is the ration of percent change in electricity consumption and the percent change of other product price. In the case of customers that cogenerate using gas turbine, prices of natural gas or of other gas sources may affect the response of electricity consumption in a given period. David [5] studied the effects of electricity prices in other periods in the consumption of electricity in the current period, he called this effects inter-temporal price elasticity effects. Sometimes the utility can not efficiently predict cross price elasticities, because changes in marginal prices of fuel or valuation of electricity services are intrinsic of the customer operation. For instance, in the steel making process the gas by-product in the coke oven; and blast furnaces has a marginal price equal to zero for the steel cogeneration equipment. The supply availability of by-product gas may vary with the production schedule in the plant, that may not be disclosed for competitive reasons.

Even developing models that predict RTP participants to electricity prices, the utility still must expose itself to risk (losses) due to imperfect participant behavior forecasting. If the utility assumes that the participants are going to have an undesirable high consumption during some period of the day, it might propose a high price to clip demand during that period. However it might happen that participants’ valuation of electricity services in that particular period is even higher than the offered prices. And participants’ consumption of electricity is higher than expected causing prices to lower than the actual incremental costs. The same error may occur in the other direction. It might be that low prices are not low enough during some time period to create participant’s demand. If the utility had forecast correctly this lower than normal valuation of electricity services, electricity prices might be set at a lower level and attract some extra demand. The utility may correct its error margin if the RTP contract allows for utility interruptions. However the use of interruptions must be limited to contract agreement and therefore will ultimately be factored in the service cost.

VI.2.2 Using existing Utility "Software" to Calculate RTP

Kirsch et al. [10] derived an algorithm "for forecasting day-ahead hourly marginal costs" based on existent utility "operational software" to determine RTP for Niagara Mohawk Power Corp. In the case of the rate Niagara Mohawk offers RTP must reflect marginal operating costs and marginal outage costs, and would allow price to differ over time and by geographic area.
RTP may vary with geographic area because the location of loads relative to generators may affect marginal operation costs and reliability given transmission constraints. The authors modified the economic dispatching algorithm to do the 1 day ahead marginal operational and reliability cost forecasting. In reality New York Power Pool was the one running the original dispatching algorithm since Niagara Mohawk is part of the pool.

Kirsch reports that the algorithm the modifications were not trivial and the solution method must be altered, increasing computational effort and procedure complexity. The previous method would eliminate binding units or reserve constraints from computation, but the new problem needed the shadow costs of the unit bounds and reserve constraints to determine contributions to RTP. The final procedure is divided in three steps. First, forecast the next day hourly loads and external exchanges. Second, generate the problem constraints, namely, demand constraints, generator constraints (using only the committed generators), transmission constraints (using power flow analysis and B-matrix as penalty factor) and reliability constraints (pool determined reserve). Third, solve the economic dispatch for each hour of the next day. Note those transmission lines that are constraining the problem may not be tie-lines coming in and out of each area. Therefore determining the marginal transmission cost of one area may require taking the shadow prices of the transmission interface constraints as a starting point to a more involving procedure.

This procedure, however, fails to use final RTP prices as a feedback in the initial demand forecast, besides the theory of RTP extracts most of its gains from the customer response to electricity prices. The authors do not consider that RTP may be used to minimize costs related to unit commitment problem, probably because of rate characteristics and other operation constraints. After all, the utility does not need to restrict its RTP planning horizon to 24 hours, because prices are sent to customers only one day ahead. The unit commitment problem is brought in since RTP or another complementary incremental cost rate may change demand levels and system load distribution enough to change typical day patterns. When using RTP strategies, utilities must be careful to not be only changing the peak, instead of filling the valleys.
VI.3. A modified real time pricing program

This paper calculates marginal fuel costs in detail for a RTP specific program that a utility may offer to large interruptible load industrial customers. We think that the reader can use the details of this fix framework and of other specific RTP experiences and generalize to his own problem [10][17]. Caramanis et al. [2] attempt to characterize possible RTP programs according to implementation complexity levels and potential benefits. The smaller interval between price schedule updates reflects more accurately the evolving states of the system and its marginal costs. If price update intervals are too small the customer may not have the technical and economical ability respond then. An alternative to smaller notification time intervals is to require the customer to inform its consumption pattern ahead in time and tie this load informed to a take or pay contract. This procedure only reduces system load uncertainty (and marginal costs) from the modified RTP participant customer, but may be an important contribution if the number of participants is large a load information is accurate. All other customers (non-RTP participants) load sources are still uncertain, and the utility must deal with them.

Large steel industrial customers that plan weekly their operation and resource consumption dominate the load in the data we obtain for our experiments. Hence we assume, the utility follows the same time frame to update its prices and sends once a week a price schedule to all participating customers. This price schedule has of three price-quantity tiers. Each tier contains maximum load and corresponding prices for every hour in the following week. The customer must use the price schedule to plan her operations during the next week and inform the utility which tier she is going to use. If customer consumption exceeds the informed tier maximum load at any hour of the week, the excess energy price must equal to the period marginal (incremental) cost plus a contractual penalty adder. Therefore, the customer must select the tier that provides the minimum energy requirements for every hour in the week ahead. This procedure by itself promotes customer interest in controlling peaks.
### Table VI.1 Symbol glossary.

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A\dder_t$</td>
<td>Fixed embedded cost portion of the real-time price used to remunerate fix costs used at time $t$.</td>
</tr>
<tr>
<td>$D_t$</td>
<td>Forecast system power demand during time interval $t$, that is price independent.</td>
</tr>
<tr>
<td>$D_{tq}(p_{eq})$</td>
<td>Forecast system power demand during time interval $t$ in tier $q$, given the vector of electricity prices for tier $q$.</td>
</tr>
<tr>
<td>$F_{ik}(p_{ek})$</td>
<td>Total fuel cost of generating unit $i$ for time interval $t$ in scenario $k$. This function represents the input/output characteristics of generating plant $i$. Besides any functional form could be used, we assumed this function is linear, like the following:</td>
</tr>
<tr>
<td>$G_{i}(t,s)$</td>
<td>Fuel cost of dispatching energy during period $t$, given unit $i$ is in state $s$.</td>
</tr>
<tr>
<td>$I_1$</td>
<td>Generating unit index.</td>
</tr>
<tr>
<td>$I$</td>
<td>Set of all generating units committed (available for generation).</td>
</tr>
<tr>
<td>$p_{e}$</td>
<td>Pre-determined maximum short run cost of electricity.</td>
</tr>
<tr>
<td>$p_{e}$</td>
<td>Minimum price of electricity to recover revenue requirements.</td>
</tr>
<tr>
<td>$p_{e}$</td>
<td>Short run marginal cost portion of real-time price of electricity at time $t$.</td>
</tr>
<tr>
<td>$P_i$</td>
<td>Maximum power output (kW) of generating unit $i$.</td>
</tr>
<tr>
<td>$P_{iw}$</td>
<td>Power output (kWh) of generating unit $i$ for time interval $t$ in scenario $s$.</td>
</tr>
<tr>
<td>$p_{ri}$</td>
<td>Probability associated with the outcome of state of nature $k$.</td>
</tr>
<tr>
<td>$p_{si,k}$</td>
<td>Purchase spot price of electricity at time $t$.</td>
</tr>
<tr>
<td>$p_{si,k}$</td>
<td>Export spot price of electricity at time $t$.</td>
</tr>
<tr>
<td>$ST_{i,t,s}$</td>
<td>Starting cost of generating unit $i$ at time interval $t$.</td>
</tr>
<tr>
<td>$ST(t-1,r,t,s)$</td>
<td>State transition costs (start-up and shut-down cost) from state $r$ in period $t-1$ to state $s$ in period $t$.</td>
</tr>
<tr>
<td>$S_i$</td>
<td>Set of all possible states in period $t$ in the dynamic programming formulation. Possible states are unit is on or unit is off.</td>
</tr>
<tr>
<td>$TC_i(t,s)$</td>
<td>Minimum total cost (start up plus fuel costs) unit $i$ accumulated from the first period up to state $s$ in period $t$.</td>
</tr>
<tr>
<td>$u_{i,t}$</td>
<td>Discrete variable, indicates that unit $i$ is on at time $t$ if equal to 1, and off if equal 0.</td>
</tr>
<tr>
<td>$\lambda_{i,k}$</td>
<td>Lagrangean multipliers of demand constraint in period $t$ scenario $k$.</td>
</tr>
<tr>
<td>$\mu_{i,k}$</td>
<td>Lagrangean multipliers of reserve constraint in period $t$.</td>
</tr>
<tr>
<td>$\nu_{i}(DLUC)$</td>
<td>Objective function value of the dual of the unit commitment Lagrangean relaxation.</td>
</tr>
<tr>
<td>$\nu_{i}(LUC)$</td>
<td>Objective function value of the unit commitment Lagrangean relaxation.</td>
</tr>
</tbody>
</table>
VI.3.1 A methodology for the modified real-time price calculation

Load uncertainty becomes an important factor in calculating the final price in a RTP program that announces its prices weekly. The utility can actually attribute probability to different scenarios, given system historic data, hence the procedure for determining the marginal fuel cost portion of RTP called is planning under risk. The electric utility has a wide range of tools to forecast possible energy system scenarios in the short to medium planning horizon, such as, time series, weather response and adaptive forecasting models [1].

Table VI.2 lists basic steps the method follows. The utility must take the first step and determine possible non participant load scenarios for the planning period ahead and associated outcome probability. For each scenario the utility will estimate all non-participant load, reserve requirements, hourly buying and selling electricity prices and hourly interconnection capacity to import and export power. The utility must select also 3 quantity tiers to propose to the RTP participant customers. This quantity selection uses previous utility knowledge and observation of RTP participant usage. Next, the utility will solve one two-stage unit commitment problem for each tier level, q. Each two-stage unit commitment solution must provide a feasible commitment strategy and dispatching solution for every hour in the planning horizon of all scenarios. The dispatching solution must minimize the expected dispatching fuel costs. Each

Table VI.2 Real-time price determination algorithm

1. Estimate possible scenarios for non participant loads
   1.1. Load for each customer class
   1.2. Reserve Requirements
   1.3. Import and Export Energy Prices
   1.4. Scenario Probabilities
2. Estimate possible load tier for RTP participant loads
   2.1. Possible Participant Load Levels
3. Solve unit commitment under risk
4. Utility communicates to participant price schedule to participants.
5. Participant determines its expected consumption.
6. Participant communicates to utility tier selected.
7. Utility adopts minimal cost strategy.
energy utilization tier determines a different unit commitment and marginal fuel price solution. Hence the marginal fuel costs and unit commitment mix in each hour will be used to calculate the RTP of each utilization tier. Return to fix cost and other contractual requirements are factor in the final price as adders to the marginal fuel cost depending on the unit commitment configuration at each hour.

VI.3.2 Two-stage unit commitment model

The unit commitment problem objective is to minimize generating units on, off and fuel cost considering the dynamic dependencies of each time interval in the planning horizon. This problem is equivalent to the capacitated plant location problem [4], which may use a dynamic programming or mixed integer programming (MIP) formulation for the solution. Usually the commitment problem assumes a single scenario that may occur with probability equals to one. This kind of formulation does not address demand uncertainty because it analyzes only the most likely outcome during the planning horizon. Under the conditions of low variation of demand or resource prices, this approach is acceptable, since one expects that the minimum expected cost of production maybe very close to the minimum mean cost of production.

We formulated the unit commitment problem as a MIP and changed the traditional model into a two-stage problem to introduce the decision analysis under risk. The two-stage formulation explicitly deals with decisions in the present (here and now variables) that will affect decisions in the future (there-and-then variables) [18]. In the two-stage unit commitment problem, the present decision of having a unit turn on during time period $t$ in the future must consider its affects over a set of possible demand scenarios in the future. The two-stage programming treats sequential decisions as the risk averse individual would, given a decision today will reduce the set of possible alternatives in the future, one should fix the present that minimizes present costs and expected future costs.

Since the utility wants a reduce its risk, it must consider the alternative behavior of loads that are hard to forecast (non participants). No matter which scenario the future revels, the utility must have a commitment capable to serve it. The traditional one scenario approach may take a pessimistic or average scenario and minimize its commitment and dispatching costs. The route this paper takes is to consider three possible scenarios and run the two-stage unit commitment
model with these scenarios for each RTP tier. Note that the RTP tiers, once selected by the customer are considered fixed, hence reducing forecasting variability. The multiple scenario methodology is advantageous over the one scenario methodology if the average overestimation and underestimation costs of the former are significantly lower than the one from the latter. This may be the case in the case of a more competitive industry with the advent of the one-hour energy markets (import and export energy), where planning ahead and risk will start to have higher weight in, where planning ahead and risk will start to have higher weight in electricity prices.

Equation VI.1 shows the objective function of the two-stage unit commitment model. The objective function divides the here-and-now variables as the ones without \( k \) subscript from the there-and-then variables, with the \( k \) subscript. There-and-then variables have one instance for each possible scenario in the future. Each unit may be in two states on or off \((u_i = 1 \text{ or } 0, \text{ here-\&-\now variables})\), which will be the same for every scenario. Each possible combinations of the on and off units determines a system state in any particular time period for all scenarios. Each time a unit is turned on there is a cost associated with it, which is represented by the \( ST \) parameter. Shut down costs can be considered in the same way, besides they weren’t in the current formulation. For every scenario and time period all possible system state must be analyzed to determine the dispatching strategy with that provides the minimum fuel cost to traverse the period. For each scenario, the energy units’ output, import and export energy must be determined to minimize the output cost expected value(second set of braces).

\[
\nu_r^{(UC)} = \min_{r, u} \sum_{i \in T} \sum_{i \in I} \left[ ST \left[ 1 - u_{i(t-1)} \right] u_i \right] + \sum_{i \in T} \left[ \sum_{i \in I} p s_{ik}^P P_{ik}^P - p s_{ik}^E P_{ik}^E + \sum_{i \in I} \left[ p s_{ik}^p (P_{ik}^p \cdot u_i) \right] \right] pr_e
\]

Equation VI.1 Two-stage unit commitment problem objective function.

The objective function minimization process must satisfy demand, reserve, unit generation limit, import limit and export limit constraints for all time periods. Note that unit generating limit constraint are the link to the two stages of the problem, since energy output must satisfy demand constraints on every scenario \( k \), but there is only one commitment solution for all scenarios. Reserve constraints must satisfy the scenarios expected demand and the reserve margin for all time periods. Import and export energy levels.
Equation VI.2 Demand constraints.

\[
P_{ik}^D - P_{ik}^E + \sum_{i \in I} P_{ik} = D_{eq}(pe_{eq}) + D_{eq} \quad \forall t \in T, \forall k \in K
\]

Equation VI.3 Reserve constraints.

\[
\sum_{i \in I} u_{it} - \sum_{k \in K} [D_{eq}(pe_{eq}) + D_{eq}]pr_{i} - R_{i} \geq 0 \quad \forall t \in T
\]

Equation VI.4 Unit generation lower and upper bounds. Note that if the unit \( i \) is not committed in period \( t \) and \( u_{it} = 0 \) then energy output is fixed at zero.

\[
u_{it} = 0 \text{ or } 1 \quad \forall t \in T, \forall i \in I
\]

Equation VI.5 Integrality constraints for state of unit \( i \) at time \( t \).

Equation VI.6 Energy imports lower and upper bounds.

\[
P_{ik} \geq 0 \quad \forall t \in T, \forall k \in K
\]

Equation VI.7 Energy exports lower and upper bounds.

\[
P_{ik} \geq 0 \quad \forall t \in T, \forall k \in K
\]

The utility also faces the dispatching problem at the unit commitment level, because it needs to determine the output of each spinning generating unit. The probability weight sum of the fuel cost equations in the objective function represents total expected fuel used to serve demand. The fuel cost equations we use in this problem are a linear equation for the sake of solution simplicity, however other functional forms may be used with the same general solution algorithm.

\[
F_{it}(P_{ik}) = \alpha_{i} + \beta_{i}P_{ik}
\]

Equation VI.8 Fuel cost equation.
VI.3.3 Lagrangean relaxation solution method

Merlin [11] and Zhuang [19] solved the one stage problem using a Lagrangean relaxation search method. The same method with appropriate modifications is used in this paper. Note that the solution this method is a heuristic solution to the actual optimal, but it was adopted because of problem dimensions and solution time requirements.

Equation VI.9 shows the Lagrangean relaxed objective function of the two-stage unit commitment problem, which adds the demand and reserve constraints in the objective function, weighted by Lagrangean multipliers. Constraints of the minimum and maximum generation capacity remain unchanged. The problem is still a minimization subject to Equation VI.4, Equation VI.5, Equation VI.6, and Equation VI.7. To reduce notation we call

\[ D_{q} = D_{q}(p_{a}) - \overline{D}_{a} \], since the index \( q \) does not vary in each unit commitment problem.

\[ \min_{\lambda_{i}^{u}, \lambda_{i}^{l}, \lambda_{i}^{p}, \lambda_{i}^{r}} \sum_{i \in T} \left( \sum_{i \in I} \left( ST_{i}(1 - u_{i(i-1)}).u_{i} \right) + \sum_{i \in I} \left( \sum_{i \in T} \frac{F_{i}(P_{iik})u_{i} + ps_{ia}p_{ik} - ps_{ia}p_{ik}^{e}}{pr_{k}} \right) \right) \]

Equation VI.9 Objective function of the Lagrangean two-stage unit commitment problem. Demand and reserve constraints were included in the objective function.

If we reorder the variables, one can notice that the problem becomes separable in the units \( i \). However, we still must find a way to determine the values of the Lagrangean multipliers. Since the Lagrangean multipliers are variables of the dual problem (DLUC), one can solve the dual transforming the objective function as Equation VI.10 shows.

\[ \max_{\lambda_{i}^{u}, \lambda_{i}^{l}} \lambda_{i}^{u} \left( ST_{i}(1 - u_{i(i-1)}).u_{i} \right) + \lambda_{i}^{l} \left( \sum_{i \in I} \left( \sum_{i \in T} \frac{F_{i}(P_{iik})u_{i} + ps_{ia}p_{ik} - ps_{ia}p_{ik}^{e}}{pr_{k}} \right) \right) \]

Equation VI.10 Objective function of the dual problem of the Lagrangean two-stage unit commitment problem.
After some reorganization we present in Equation VI.11 the dual of the two-stage unit commitment lagrangean relaxation objective function. This problem is subject to constraints imposed by Equation VI.4, Equation VI.5, Equation VI.6, and Equation VI.7.

Equation VI.11 Two-stage dual lagrangean objective function.

\[
\begin{align*}
\sum_{t \in T} \left\{ \mu_t \left[ \sum_{k \in K} D^u pr_t + R_t \right] + \sum_{k \in K} \lambda^u_k \cdot D^u \right\} + \\
\min_{\mu_t, \mu_k^u} \left\{ \sum_{t \in T} \left[ \left( p^s \cdot p^b - p^s \cdot p^e \right) pr_t + \lambda^u_k \cdot \left( p^e - p^b \right) \right] \right\} + \\
\sum_{t \in T} \left\{ ST \left[ 1 - u_{(t-1)} \right] \cdot u_t - \sum_{k \in K} \lambda^u_k \cdot P_{in} - \mu_t \cdot \bar{P}_t \cdot u_t + \mu_t \cdot \sum_{k \in K} F_{in} \left( P_{in} \right) \right\}
\end{align*}
\]

Equation VI.11 divides the problem in three parts, each one of them presented in a different line of the equation. Starting by the bottom, the third line is the primal minimization decision variables associated to the power generating units, namely the unit commitment variable, and power generated. The second line represents the primal minimization of decision variables associated with power exported and power imported. The first line, finally, has no primal variables and, therefore, requires no the minimize operator. The third line of Equation 11 is separable in sub-problems of individual units i. Note, however, that the sub-problems still have integer non-linear terms of integer variables that are not of trivial solution directly. The way to avoid the non-linearity is to transform each unit sub-problem in a dynamic programming formulation dealing with the unit commitment and dispatching decision of individual units. Each one of these sub-problems became extremely simple to solve since there are only 2 states to be searched in the DP tree. The unit sub-problem will decide whether to turn the unit on or off for each time period considering start-up costs and expected fuel costs given an expected dispatching strategy for each different scenario. In the DP forward form each sub-problem look like the following:
\[ TC_i(t,s) = \min_{r,s} \{ G_{i}(t,s) + ST_i(t-1,r,t:s) + TC_i(t-1,r) \} \]

Equation VI.12 Dynamic program state equation representing total cost accumulated when unit \( i \) changes from state \( r \) in time \( t-1 \) to state \( s \) at time \( t \).

The subscript of the units \( i \) represent that the costs are originated exclusively from that unit. Note also that \( G_{i}(t,s) \) are exclusive from the unit. At this point the Lagrangean multipliers are fixed at some level and the state \( s \) determines if the unit is on or off, that is, if \( G_{i}(t,s) \) is to be determined, or if it is zero, respectively.

\[
G_{i}(t,s) = \min_{P_{ik}} \text{ s.t. } \begin{align*}
\sum_{k \in K} (a_i + \beta_i P_{ik}) p_{ik} - \sum_{k \in K} \lambda_{s} \cdot P_{ik} - \mu_{r} \cdot P_{sr} \\
P_{ik} u_{ik} \geq P_{i}, P_{ik} u_{ik} \leq P_{i}
\end{align*}
\]

Equation VI.13 Dual two-stage fuel cost problem for unit \( i \) in period \( t \).

VI.3.4 Calculating the final RTP price

The final RTP price for each time period will be equal to the sum marginal fuel cost multipliers (from demand and reserve constraints) and an adder. The adder represents a return to fix or embedded costs of utility resources being (generating units, transmission and distribution lines) used during that time period. The adder represents the long run marginal valuation of capacity investments, and as such, will not guaranteed that its total revenues equal embedded costs unless the utility capacity is optimal. Note that the final price for tier \( q \) uses the multipliers of separate runs of the unit commitment algorithm. We avoid to include this index before to save the reader from another symbol. The adder may vary over time and tier depending on what resources were used during a time period. For example, if for serving the high tier the unit commitment solution requires a gas turbine was turn on in period \( t \), the adder will include an extra remuneration for this fix investment.

\[
pe_{\text{add}} = E(\lambda^*_t) + \mu^*_t + \text{Adder}^*\]

Equation 14 Calculation of RTP based on marginal fuel costs.
VI.4. Testing the method

In order to test the method we used data from a large midwest utility and the interruptible power consumption of some of its customers. Table VI.3 shows the possible scenarios considered and price tiers. Each row requires the solution of a full two-stage unit commitment problem that includes all the column represented scenarios. The experiment assumed a period of high consumption like summer. It used the high scenario as the annual average hourly demand plus 2.5 times the standard error observed in that hour. The medium and lower scenario used the same kind of calculation, but with standard error times 2 and 1.5.

VI.5. Empirical Results

Figure VI.1 shows some preliminary results of our research. The columns in the graphs show the expected participant load (tier) and the lines the marginal fuel costs. The lowest line shows reserve constraints shadow costs (reserve marginal fuel costs = $\mu_R = \mu_c$), the group of lines in the center of the graphs show the demand constraints shadow costs (demand marginal fuel costs = $\lambda_D = \lambda_s$) of the three scenarios. Finally, the higher line represents the sum of the reserve and expected demand marginal costs, what would be the marginal fuel cost portion of

<table>
<thead>
<tr>
<th>Load Tiers</th>
<th>System Load Scenario</th>
<th>High</th>
<th>Medium</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>High</strong></td>
<td></td>
<td>$\text{Av}^\text{SYS}+2.5\cdot\text{Std}^\text{SYS}$</td>
<td>$\text{Av}^\text{SYS}+2.0\cdot\text{Std}^\text{SYS}$</td>
<td>$\text{Av}^\text{SYS}+1.5\cdot\text{Std}^\text{SYS}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$\text{Av}^\text{RTP}+2.0\cdot\text{Std}^\text{RTP}$</td>
<td>$\text{Av}^\text{RTP}+2.0\cdot\text{Std}^\text{RTP}$</td>
<td>$\text{Av}^\text{RTP}+2.0\cdot\text{Std}^\text{RTP}$</td>
</tr>
<tr>
<td><strong>Medium</strong></td>
<td></td>
<td>$\text{Av}^\text{SYS}+2.5\cdot\text{Std}^\text{SYS}$</td>
<td>$\text{Av}^\text{SYS}+2.0\cdot\text{Std}^\text{SYS}$</td>
<td>$\text{Av}^\text{SYS}+1.5\cdot\text{Std}^\text{SYS}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$\text{Av}^\text{RTP}$</td>
<td>$\text{Av}^\text{RTP}$</td>
<td>$\text{Av}^\text{RTP}$</td>
</tr>
<tr>
<td><strong>Low</strong></td>
<td></td>
<td>$\text{Av}^\text{SYS}+2.5\cdot\text{Std}^\text{SYS}$</td>
<td>$\text{Av}^\text{SYS}+2.0\cdot\text{Std}^\text{SYS}$</td>
<td>$\text{Av}^\text{SYS}+1.5\cdot\text{Std}^\text{SYS}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$\text{Av}^\text{RTP}+2.0\cdot\text{Std}^\text{RTP}$</td>
<td>$\text{Av}^\text{RTP}-2.0\cdot\text{Std}^\text{RTP}$</td>
<td>$\text{Av}^\text{RTP}-2.0\cdot\text{Std}^\text{RTP}$</td>
</tr>
</tbody>
</table>
the RTP price. All the solutions were at least 5% of the true optimal.

The results did not show much difference in the final lagrangean multipliers. We attribute this to three reasons. First, the data sampling was too low for the utility installed capacity, since the high scenario could not cover the utility observed peak. Second the utility in question has notorious excess capacity problem, and it seems that the amount of interruptible power involved in this rate did not significantly change the commitment of units. Finally, the final adder is not considered at this point and some gas turbines were actually used in the high tier while not in the low or medium tier. The final values of the objective differ in about 100 thousand dollars between two consecutive tiers. What show potential savings over the current system, if this amount of savings would be enough to implement a program as this, the utility stockholders and commissioners should be the ones to answer.

VI.5. Conclusions

A more customer oriented electric service is better suited for a more competitive generation market, for handling environmental concerns, and for satisfying regional development packages [9]. In this sense RTP transfer decision power from the utility to the customer about how much electricity services worth at some time of the day or the year. Some customers may therefore prefer to change their consumption pattern or invest on equipment that would allow them to buy less from the utility during high price periods and more during lower price periods. Calculation of real-time price rate depends on the kind of electricity the customer is buying from the utility, but it will mainly reflect fuel and reliability costs.

Advantage of using a RTP as described in this paper will depend on the current utility excess capacity and amount of power exchange with neighbors.
Figure VI.1 Marginal fuel costs for low (a), medium (b) and high (c) load tiers.
VI.7. References


