# Integrated Resource Planning in 2004?

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We are now entering another phase of transition for the electric utility industry, as well as for related industries. Most of the electricity in this country is supplied by regulated, investor-owned monopolies; investors run the gamut from large pension funds to individuals. Deregulation is being promoted by a number of interest groups, including industrial customers, other suppliers, utilities themselves, and some regulators. Some elements of a competitive marketplace are now appearing, and others may occur in the near future.

Competition can take many forms. Competition can occur either:

- On the demand side of the meter (e.g., electric service companies or ESCOs, retail wheeling, fuel substitution, and energy efficiency); or
- On the supply side of the meter (e.g., nonutility generators, other neighboring utilities, and other distant utilities).

This paper speculates on the changes that may occur in the next ten years. We discuss elements of the transition for each of the above two categories. The history and current state of utility planning are also presented for background.

## Introduction

In ten years, what form will planning take at a successful electric utility? Speculation abounds about the long-term results of competition and deregulation, and the degree to which either will occur.

Currently the predominant planning approach is integrated resource planning (IRP). The IRP approach gained prominence rapidly. In less than a decade after its introduction, it became the tool of choice for utilities and commissions that wanted lower costs, more efficiency, and environmental improvement. However, IRP is becoming obsolete as quickly as it gained prominence. In many states, particularly those where collaboration drives the planning process, a single IRP "cycle" lasts for more than a year and costs millions of dollars. 'Many have concluded that IRP is so complicated, detailed, time consuming, and costly that it is not a viable decision-making tool.

Competition and deregulation will lead to shorter planning horizons, an increased need for flexibility in plans, and a focus on competitive positioning. As utilities become more market-oriented, utility planning must change to address external as well as internal issues. An external orientation means that planning will focus on customer needs, not utility loads. Power supply issues, which currently drive most IRP processes, will be only one of a number of considerations. In the future, the definition of IRP may be broadened to include competitive positioning. On the other hand, the IRP process may be abandoned altogether. What is the value of a planning process that identifies a leastcost resource plan when it turns out that competitors are serving the demands that drove the plan in the first place?

Utility planning, like the electricity market, is in transition. Utility planners are considering their options if deregulation occurs. Some utilities may choose to be lowcost suppliers of power and specialize in generation of power as wholesalers. Other utilities may choose to provide energy services to their customers and become power brokers, as well as providing direct services such as lighting, heating, or cooling. Planning approaches will vary depending on how a utility defines itself and its market. The extent of deregulation, which may vary from little regulatory change to full deregulation, will also influence planning approaches and techniques. For utilities which elect to provide a variety of supply- and demand-side services, the IRP approach may continue to be used. In other cases, different techniques may be more advantageous.

In this paper, we will review how the current planning processes evolved, the reasons for pressure to deregulate electric utilities, and the uncertainties planners face in decision making for the foreseeable future.

## Background

The term "integrated resource planning" encompasses a broad range of planning approaches. As practiced today, IRP is the continuous process of identifying and evaluating combinations of demand-side and supply-side resources to achieve specified objectives and meet forecasted demand. Through this planning process, the utility and other participants seek to find the least-cost manner in which loads can be met or modified while meeting specified constraints, such as maintaining a given level of reliability and customer service.

In the past, utilities have operated under an "obligation to serve" philosophy, which has led them to develop leastcost, reliable resource plans. Although long-term planning has been a critical activity in the electric utility industry for some time (in part due to the size of and long lead times needed for central station power plants, and in part due to the need to anticipate the transmission and distribution systems required to support community growth), traditional electric utility planning consisted largely of matching expected customer load growth with the building of new generating capacity or energy purchases.

During the 1980s, as the costs associated with that planning approach rose, utilities and others became interested in expanding their planning methodologies to consider opportunities to modify customers' use of electrical energy. Planners no longer took the level and timing of customer demand as a given, but as a variable that could be modified by demand-side management (DSM) programs. DSM programs include a variety of approaches to modify customer load (e. g., customer incentives such as rebates or loans, information, direct installation, or incentives to manufacturers or product dealers). DSM load modification goals include peak reduction, energy reduction, off-peak load growth, and other load changes.

The transition of the industry away from a monopoly structure began with the passage of the Public Utility Regulatory Act (PURPA) in 1978. This act defined avoided (incremental) cost as the price utilities should pay for certain types of nonutility generator (NUG) power. The act also led to the valuing of DSM "negawatts" at marginal costs. With the price increases and uncertainty caused by the oil embargoes of the 1970s, the transition from a regulated natural monopoly (in which sales prices were based on average costs) led to the expectation that costs for new units (incremental costs) would be higher than average costs. This expectation launched the NUG and DSM industries.

DSM programs now account for a significant portion of the new resource plans at most utilities. Also, since 1978, 50% of all new generation in the United States has been built by nonutilities. In California, the figure is 90%.<sup>2</sup> In the United States, at least 43 state regulatory commissions now require utilities to consider some type of IRP process that incorporates DSM options and environmental considerations into the acquisition process for new resources.

Over the past ten years IRP has helped utilities to think about how to expand their service offerings, negotiate with other power providers, improve the quality of the plans adopted, and minimize confrontations with ratepayers, environmental advocates, and others through the use of collaborative process. However, IRP is now under pressure because of deregulation and competition, technological change (e.g., microwave heating and drying, ultraviolet curing, membrane separation, and other recent electric and gas technologies), and economic change (e.g., trade agreements and global competitive pressures). Long gone are the days when technological advancements in power plant development and economies of scale lead to expectations that electric power will be too cheap to meter in the future. Also gone are the days when simple linear regression models are adequate to forecast demand for power and the price of electricity is not a key variable in the equation used to project customer usage. In the past 20 years we have learned that expectations for the future can change quickly and dramatically.

## Competition

Competition can take many forms. Competition can occur either:

- On the demand side of the meter (e.g., electric service companies or ESCOs, retail wheeling, fuel substitution, and energy efficiency); or
- On the supply side of the meter (e.g., nonutility generators, other neighboring utilities, and other distant utilities).

Utilities are currently experiencing both types of competition through resource bidding and other regulatory experiments. However, competition is still limited by regulation, including limitations on wholesale and retail wheeling. The National Energy Policy Act (NEPA) of 1992 and some state regulatory commissions support wheeling. This support not only enhances current wholesale wheeling but also further opens the door to competition for customers through retail wheeling. Many observers expect electric utilities to respond by separating into their component parts (i.e., into generation-only and transmission and distribution (T&D) companies). If utilities separate into their component parts, there would seem to be no role for IRP. On the other hand, NEPA also supports a broader application of IRP, one that requires IRPs from a number of specifically listed utilities and that requires state regulatory commissions to consider using IRP.

From a competitive, or strategic, viewpoint, IRP currently has two critical conceptual weaknesses: (1) it focuses on cost minimization as the main goal of the planning process, and (2) it assumes that customer loads are somewhat predictable and that customers in a given area will be served only by the "host" utility. Competition undermines both the assumption that lowest cost is always equivalent to the greatest value and the assumption that customers are made dependent, and therefore relatively predictable, by their geographical location.

With deregulation and increased competition in the natural gas, airline, and telecommunications industries as examples, and with the impetus provided by PURPA, power producers of all kinds are seeking to expand their markets. With retail sales of electric power becoming increasingly deregulated, the number and type of potential competitors will greatly increase. These new competitors will offer lower rates, more appropriate or more comprehensive services, or other features to appeal to target markets. Potential competition for electric utility service may come in the form of:

- Substitution of gas for electric power;
- Substitution of other products for current end uses (e.g., insulation for heating, fiber optic light source for light bulbs);
- Energy service companies that provide DSM measures for a share of the savings;
- Independent power producers;
- Cogeneration (on-site self-generation);
- Utilities that draw customers to other territories by offering lower rates;
- Other countries that offer lower electric rates and less expensive labor;

- Direct utility competition via transmission access; and
- New entities (or differently structured utilities) that package financing, equipment, maintenance, operations, and energy.

The basic test for resources selected under the IRP process appears to be the same as that for resources selected under conventional resource planning-customer satisfaction. However, utilities previously assumed that customers were satisfied as long as rates were low and stable and the power system was reliable, and used least cost at a target reliability level as the criteria for resource selection. As IRP evolves, so too must the definition of customer satisfaction. IRP faces the challenge of expanding the criteria for resource selection to encompass the full range of a utility's market potential. Simply basing resource selection on the conventional criterion of cost minimization for a set reliability level will not be adequate in the competitive environment that utilities face.

In the new world of competition in the electric utility industry, the constraint of reliability is also lessened. With the focus on open transmission access and resource alternatives like nonutility generators and demand-side management, diversity is increased while reliability is removed as an element of utility control. State and federal capacity planners and regulators are increasingly bearing the responsibility for regional reliability levels. This winter's experience in Washington, D.C., when the federal government and businesses had to close due to Pepto's inability to serve their load, may be a precursor of coming events. Some feel one to two days of outages are an acceptable tradeoff for other perceived benefits, such as reduced environmental impacts. Others think there will be a negative customer reaction to such a situation, as there was to Con Ed outages in New York in the 1970s which affected others in the region as well.

Ten years from now, utility resource planning, in whatever form it then exists, will face a myriad of purchases and sales options (or, in the language of IRP, supply- and demand-side options). Market research will be needed to identify customer needs and the value they place on having these needs met. Utilities will need to understand their customers' businesses and objectives (e.g., a computer time-share business may require 100% reliability, whereas many industrial customers in the past have been able to handle scheduled interruptions in their service). Utilities will need to assess their capabilities and constraints to decide on the customer needs that they can best meet.

### Transitioning to the Future

"Cheshire-Puss, " she [Alice] began, "Would you tell me, please, which way I ought to go from here?" "That depends a good deal on where you want to get to, " said the Cat.

"Well, I do not really know, " she said.

*"Then it does not much matter which direction you go, " replied the Cat.* 

Lewis Carrol1<sup>3</sup>

Electric utilities are faced with the need to rethink their corporate missions and their objectives in light of the changing environment of their industry. They have to decide where they want to go. Utilities can respond to the changing environment of the electric utility industry in two ways. They can assume a "business as usual" mentality and ignore potential changes until they happen or they can respond proactively to the potential changes. A proactive response entails addressing three key questions:

- •Who are your clients?
- •What are their needs?
- What are value-added strategies for addressing these client needs?

The hallmarks of a proactive response are market-focused planning, shorter planning horizons, flexibility in plans, resource bidding, performance-based ratemaking, contingency planning, and creative approaches to markets (see Figure 1). We discuss each of these topics separately.

#### Market Focused Planning

Changes in the utility industry, chief among them the virtually unstoppable trend toward increased competition, will continue to drive changes in resource planning. To thrive in a competitive market, utilities must both understand their customers' business objectives and assess their own capabilities and constraints to determine which customer needs they can most efficiently and most profitably meet. Customer intelligence is the key to understanding customer value; competitor intelligence is the key to deciding which market niches a utility can fill competitively.

In the short term—the next one to three years-utilities may step back from IRP (as some are already doing). Or they will find ways to adapt the process to produce the desired results, broadening the definition of IRP to include competitive positioning. Either way, utilities will put more emphasis on the rate impacts of alternative strategies, on



Figure 1. Transmomng to the Future

increasing their flexibility, and on some means to reflect customer value (not just cost) in the resource strategies (Chamberlain and Herman 1993; Herman and Chamberlain 1993; Braithwait and Caves 1991; Hobbs 1991).

Competitive issues require electric utilities to use different planning techniques than what they have used in the past. Japanese business techniques have proved successful in a number of competitive markets and can provide some insights on planning for the electric utility industry. One Japanese planning technique is to be highly responsive to changes in the market. To use this technique, electric utilities would have to know their markets and focus on near-term customer needs and issues. A Japanese market assessment technique is to observe product sales and note customer comments. This technique helps to identify *why* people are buying products; it provides more information for product development than just observing *what* people are buying.

However, at the same time that they are responding to the near-term needs of their customers, Japanese companies are also planning how best to position themselves in the market over the long term. Thus, successful Japanese companies make long-term capital investments while retaining flexibility to retune their market response. In preparing their action plans, they consider more than just historical trends.

A classic example of Japanese business techniques in action may be seen in the development of the fax machine and its subsequent marketing. Fax machines were actually developed by several American companies, which focused their early sales efforts on large corporations. However, these companies did not attempt to enter other markets because their market research showed that there was no potential in these markets. This failure in market research occurred because it focused on the features of the equipment, not customer desires. Not unexpectedly, no one wanted fancy telephone equipment that cost \$1,500 plus \$1 per page.

The Japanese, however, looked at trends in related activities, noted the rapid growth in Federal Express and other delivery services, and saw an opportunity. They saw a customer preference for improved communications, and focused on this need. Today, none of the many types of fax machines on the market is made in America. And in only five years, fax machines have changed business *and* personal communications profoundly (Drucker 1992). Electric utility plans need to respond as quickly to take advantage of changes in customer preferences and behaviors.

#### **Creative Approaches to Markets**

The next generation of IRP will probably involve the full integration of customer service planning with system planning, pricing, and evaluation. The shift in focus will come about as both commissions and utilities extend the standard practice tests of cost-effectiveness to reflect customer value. The current tests examine the changes utility programs produce in the electricity market (i.e., the market for kilowatt-hours).

However, the value of energy service to customers is not confined to the electricity market: customers value energy services, such as cooling, heating, lighting, motor power. The value of these services is measured in the market for energy services, not the market for electricity. Electricity is a derived demand. The standard practice tests are insufficient in a deregulated market where customers have the power to choose among services and suppliers; the tests must be extended so that they address the energy services market if value to customers is to be reflected in assessments of cost-effectiveness.

As utilities come to recognize that customers value enduse energy services, not kilowatt-hours, they will move away from programs that yield energy savings but inconvenience their customers (for example by requiring them to apply for rebates, agree to interruptible service, incur financing obligations, or accept performance risks). Higher lumen levels, higher precision, better reliability, and even the possibility of buying *more* cooling, heating, lighting, etc., owing to efficiency, to name a few examples, will become the criteria for program selection.

To date, most regulators do not formally recognize customer value as a basis for planning utility services; but utilities that ignore customer value run the risk that they will lose market share to other energy providers. Assessing program options from the perspective of customer value within the IRP process provides planners with additional information that may be potentially powerful in utility decision making. Thus, those utilities that are already beginning to recognize customer value will have a competitive edge.

#### Shorter Planning Horizons

Acknowledgment of the inherent uncertainties of the competitive marketplace also leads companies to shorter planning horizons. Utility forecast horizons have shortened to ten years or less (formerly, forecast horizons were 15 to 30 years), and most effort is now focused on the first five years of the forecast. The shorter forecast horizon corresponds to the shorter resource planning horizon that has been made possible by increased reliance on competitive bidding to acquire energy resources. Significant resource options have been identified through bidding, and these resource options have shorter planning horizons than those for large (800 MW or more), singleunit options, such as coal plants, hydroelectric projects, and nuclear-generating units.

Electric utilities began using long-term (15- to 30-year) forecasts because of the long lead times required for the planning and construction of large power plants. A number of factors have led electric utilities to focus on shorter planning horizons. A three- to five-year planning horizon is more and more becoming the focus of management because it is increasingly difficult to speak with much assurance about trends over a longer period. As regulators have implemented IRP requirements, they have also included requirements for two- to three-year action plans; these requirements have also led to a focus on near-term decision making.

In some industries, such as consumer electronics, the decision time frame is only one to two years. The volatility of these markets means that business plans need to change rapidly to take advantage of opportunities and to avoid losses. As electric utilities shift to competitive planning, they must recognize the volatility of competitive markets while retaining their competitive advantages over the long run. In the new market environment, options that provide flexibility (which is what many DSM programs provide) will be preferred over options that limit flexibility.

#### Flexibility in Plans

As mentioned above, flexibility in planning is another response to market volatility. Electric utilities enhance their flexibility when they can delay resource commitments in a way that helps them to better conform to future conditions. For example, rather than building a single 600-MW generating plant now, a utility could add the same capacity as three 200-MW plants at intervals of three years. Thus, if load grows more slowly than anticipated, the utility can delay or even cancel the later units, avoiding significant capital costs. The installation of three smaller units rather than one large plant also improves system reliability, as this approach would reduce the single largest contingency that must be backed up with reserves. To the extent that lower reserve margins are possible, lower costs result.

Demand-side planning and power purchases also provide more flexibility with shorter lead times and off-ramps. DSM, in particular, can be increased or decreased over two to three years. Demand-side changes can also be achieved by energy service companies, which achieve significant electricity savings either as a result of market activity in the light of high electricity rates or through activities under contract to the utility as part of a competitive bid solicitation.

End-use forecasting is a technique that utilities can use to address the issues of timing and type of resource needs, particularly when demand-side resources are under consideration. This technique also increases the flexibility of utilities to adjust their plans to changing building and appliance efficiency standards and market conditions. In a competitive market, end-use information is part of the "know your customers" information a retail supplier will need.

Many utilities, such as the Tennessee Valley Authority, use decision analysis in their load forecasting and resource selection processes. Decision analysis addresses the probability of occurrence of chance events, relationships between key parameters, and comparisons between possible outcomes. This enables planners to assess both the exposure to risk and the possible effects (outcomes) of this exposure. Competition increases uncertainty and tools such as decision analysis are helpful when planning in the face of large uncertainties.

Another technique utilities can use to enhance flexibility is contingency planning. Planners prepare for a variety of possible outcomes, Customer needs and desires may change. Competitors may move to take over a market. Power purchase arrangements may not perform as expected. Contingency plans are explicit alternatives set in place to be taken under specific circumstances. For example, if the alternative is to bring a combustion turbine on line earlier than expected, some ground work could be completed well in advance of the possible contingency (e.g., preliminary design, equipment selection, and site permitting).

#### **Regulatory Experiments**

A number of experiments, such as resource bidding, auctions, and performance-based ratemaking, may be tried by regulators as interim solutions on the way to competitive markets. In the following sections, we will discuss some of these experiments, particularly those of the California Public Utilities Commission (CPUC) and their application at San Diego Gas & Electric Company (SDG&E).

In an attempt to model competitive behavior in the acquisition of power generation resources, the CPUC instigated bidding on identified deferrable utility resources (IDRs) as part of the Biennial Resource Planning Update (BRPU) proceedings. San Diego Gas & Electric implemented the IDR auction as required during the BRPU process. SDG&E also embarked on a separate bid process to assess alternatives to its proposed South Bay Unit 3 Repower. In addition, SDG&E has proposed performance-based ratemaking as an alternative to bidding. A joint SDG&E-CPUC experiment on this is currently underway.

**Resource Bidding and Auctions.** Bidding for both supply- and demand-side resources is being experimented with in a number of jurisdictions. Some 70 electric utilities have issued over a hundred resource bids in the past ten years.<sup>4</sup> Other regulated industries and their regulators (e.g., Federal Communications Commission) are also considering a variety of bidding strategies. All of these bidding programs are attempts to move toward prices that are more competitive.

In the bidding programs to supply electric capacity and energy, it should be remembered that the *lowest* price wins. This concept causes some confusion since in most auctions the highest bid price wins. The lowest price auctions can be thought of as bidding up the benefits that go to electric utility ratepayers. Electric power supply bidding structures include:

- English Auction. In most auctions using this structure, the auctioneer raises the price until a single bidder remains. For power purchases, however, the method would be to *lower* the price until only one bidder remains. The advantage of this structure is that participants see what rivals are doing and often act aggressively in lowering prices. However, bidders could collude to keep sales prices high.
- Dutch Auction. Under this structure, the auctioneer starts high and lowers the price until someone bids. For power purchases, the method would be to start the bidding *low* and increase the price until an energy producer makes the first bid. In such an auction, bidders tend to act cautiously.
- Sealed-Bid Auction. Under this structure, bids are secret, and the highest bid wins. In the case of power purchasing, the *lowest* bid would win. Collusion is less of an issue in a sealed-bid auction because the bids are sealed. Again, bidders tend to act cautiously. A sealed-bid auction was used by SDG&E to determine the cost-effectiveness of repowering its South Bay Unit 3.
- Second Price or Vickrey Auction. Under this structure the highest sealed bid wins, but the winner pays the second-highest bid price. This approach produces high bids, since participants know that if they win they will not pay as much as they bid. As applied to power purchase bidding, the *lowest* bid would win, and that bidder would be paid the next highest bid price. In

theory, this type of auction forces bidders to bid their true price and eliminates any gaming. A second-price auction was used for SDG&E's IDR bid as part of the CPUC BRPU process.

**The Biennial Resource Plan Update (BRPU) Bidding.** The BRPU bid process was a second-price or Vickrey auction. This was the CPUC's first attempt to test acquisition of power generation resources through competitive bidding. Winning bids are placed in the queue to meet future resource needs. The identified deferrable resources were those identified in previous regulatory resource planning forums. For SDG&E, its IDR units were the Encina Repowering and two geothermal (renewable) units.

Although the second-price auction format is supposed to eliminate gaming, some bidders did not submit proposals to SDG&E based on their true project capital and operating costs. For example, several windpower proposals were bid with *negative* energy costs (at negative \$610/MWh energy and a \$5,000/kW-yr capacity charge)! These proposals were an obvious attempt to reserve a place in the queue, since bidders knew that if they won, they would receive the lowest losing bid price—which would be higher than the highest winning bid price. Knowing SDG&E's project costs was also an advantage for bidders.

The premium prices to be paid for the renewable bids and the gaming of the wind project bids are both unintended results of the auction that will cause high ratepayer payments and negatively affect SDG&E's competitive position as one of the lowest cost retail utilities in the region. Consequently, SDG&E has challenged the results of the auction. SDG&E and other utilities have petitioned the CPUC to completely ignore the auction. A price cap fix to the BRPU auction and other methods of revising the auction to reduce ratepayer exposure to high renewable energy capacity prices are being explored. As of this writing, the entire BRPU solicitation has been placed on hold while the CPUC examines the changing structure of the electric utility industry.

**SDG&E's South Bay 3 Repower Bidding.** Although not required to do so, SDG&E undertook a sealed-bid auction to ensure the competitiveness of its next resource addition: repowering its South Bay Unit 3. SDG&E undertook the auction because the evolving regulatory process in California is accentuating the competitiveness of resource additions.

Prospective bidders were required to meet a number of procedural and technical requirements. To maintain objectivity, SDG&E, with the CPUC's concurrence, obtained an independent third party to evaluate all proposals, including the repowering of South Bay 3. The independent

evaluator maintained an arm' s-length relationship with SDG&E. The evaluator was able to choose the evaluation methodology and the decision criteria based on its experience and judgment. At a minimum, these criteria had to address cost, environmental benefits, transmission constraints, and risks associated with some nonprice factors.

This sealed-bid auction resulted in a more straightforward quantitative ranking of bids than was the case in the second-price auction used in the BRPU bid. SDG&E's costs to repower South Bay Unit 3 were kept confidential; though made well before bid offers, SDG&E's costs were put on the table at the same time bids were unsealed. Gaming was reduced to a minimum. Although some bidders provided overly optimistic gas price forecasts, unless the bid included a guarantee of the gas price, a common gas price forecast was used for all gas-fired bids.

This process provided SDG&E with additional experience for supply acquisition in a competitive market.

**Performance-Based Ratemaking.** As a possible alternative to bidding for new resources, a number of performance-based ratemaking (PBR) mechanisms have been put into place on an experimental basis in California. The purpose of these PBRs is to provide the utility with financial incentives linked to its performance in (1) the purchase of natural gas for resale and power plant use, and (2) the dispatch of its electric resources and the purchasing of short-term capacity and/or energy.

The PBR mechanisms provide that both shareholders and ratepayers can receive the benefits of exceptional utility performance. At the same time, the utility assumes a portion of the additional costs or cost savings depending on whether the utility provides above- or below-standard performance in the area of purchasing natural gas or other off-system energy.

SDG&E wants to replace California's current Energy Cost Adjustment Clause (ECAC) proceedings, where *the best a utility can do is to not lose*, with a PBR mechanism. Under ECAC, if the utility does well in purchasing natural gas and/or off-system power, those benefits automatically accrue to the ratepayer. However, if the utility does poorly or is simply perceived to have done poorly in the purchase of these commodities, the excess costs of providing these services accrue to stockholders after regulatory reasonableness reviews.

The Generation and Dispatch (G&D) PBR is a two-year experiment with SDG&E, which began on August 1, 1993. Instead of relying on a single annual forecast to

determine the benchmark, as is done in the ECAC proceeding to establish rates, the G&D mechanism includes a methodology that updates monthly the value of some inputs that are beyond the utility's control, These monthly adjustments lead to a benchmark of the revenue requirement for generating and dispatching electricity that removes the effect of factors beyond the effective control of the utility. This mechanism provides incentives for improvement and a model for measuring skillful utility performance. At the end of the forecast period, SDG&E's actual G&D expenses are compared to the performance benchmark. The differences between the performance benchmark and actual costs are then allocated between ratepayers and shareholders.

The competitive incentive to SDG&E for making full use of wholesale wheeling and power purchase options is large. If the utility's performance is 1% above or below the performance benchmark, the amount above or below is allocated according to a 70% ratepayer and 30% shareholder split. If the utility's performance is greater than 1% but less than 6% above or below the performance benchmark, the cost differential above 1% and below 6% is allocated equally between ratepayers and shareholders.

This experimental performance-based ratemaking mechanism employs a cost cap to determine the applicability of reasonableness review on expenses.

- If SDG&E's costs exceed 106% of the performance benchmark, the excess is paid by the utility's rate-payers, subject to ECAC reasonableness review.
- If, however, the costs are 94% or less of the benchmark, SDG&E's ratepayers automatically receive all the benefits of the cost reductions equal to and beyond the 6% savings, with *no* ECAC reasonableness review.

Thus, this mechanism is a two-edged sword; however, one edge is still sharper than the other in a way that favors the ratepayer over stockholders. In a truly competitive market, the utility planner would have to balance risk and rewards between stockholders and customers, who would no longer be "captive."

SDG&E is actively pursuing economy energy and shortterm purchase power contracts under this experiment. SDG&E is learning more about the supply options market and acquisition techniques, which will aid SDG&E in the transition to a competitive market. In a competitive market, a utility will need knowledge about competitors and power options, as well as have mechanisms in place for competitive supply acquisition.

## The Future?

If full-scale competition (or retail as well as wholesale wheeling) comes to pass in the electric utility industry, it will have become a different business. Utilities will no longer simply bring power to customers' meters; they will also provide information and expertise in all processes and equipment using energy (including interfuel trade-offs) and will provide financial assistance when needed for equipment changeovers. In some cases, this expertise will be provided by utility staff; in more specialized cases, the expertise will be provided by utility-endorsed energy service companies.

Utilities will evolve into either commodity suppliers with cost minimization strategies or energy service suppliers that seek to serve customers well beyond their existing geographic territories through a value-enhancing strategy. Some utilities will probably attempt to adopt both strategies.

Like television viewers in the cable television industry (which is expecting to allow consumers to choose from among 500 different channels of programming using addon scheduling, program description, and selection options), utility customers will be free to choose their bundle of energy services. Some customers may even pay to have their options analyzed for them.

End-use service providers, which may be utilities or entirely new entities, will sell light, heat, and motor power directly to the customer, rather than just kilowatthours. For example, a Midwestern utility has already announced plans to own and operate the motors in a factory assembly line. Another utility plans to own, install, maintain, and operate the lighting and HVAC systems in commercial buildings. This approach removes one of the last barriers to energy conservation: building managers or factory owners will have no further worry about payback from investments in efficient equipment because they will get immediate payback in the form of lower bills. Further, and probably more significant, utilities have an incentive to install the most efficient equipment to maximize their profits.

Utilities that once provided the same service throughout their territory will take varying transmission and distribution costs into consideration in their DSM marketing and will package different services by community to take advantage of varying profitability. They may even offer entirely new services, such as a solar- or wind-generated resources, to a community. And they will compete in neighboring—or even distant-service territories by offering brokered sales of power from independent power producers, dispersed generation, other fuels (including oil, kerosene, and propane), and DSM services. However, the industry itself will face competition from service providers not now considered to be in the energy market. Telephone companies, cable television, and other services connected to customers' homes and businesses will offer "smart home" and "smart business" services that will probably include energy and load management options such as sophisticated heating, ventilating, and air conditioning (HVAC) thermostat programming and remote control. These future competitors may also be able to provide detailed end-use energy usage feedback mechanisms that will provide customers with clear and concise information about the benefits of efficient equipment.

Thus, the next generation of utility planning may be a full integration of customer service planning, system planning, pricing (ratemaking), and evaluation. Utilities should take steps now to develop data, models, and procedures for this full integration. Meeting the challenges and taking advantage of the opportunities over the next ten years will require commitment at all levels of the utility organization and perhaps some restructuring of corporate goals and objectives. By taking the steps to address competitive market issues now, utilities will be well positioned to make the transition into the twenty-first century a momentous one. Just as electric lighting symbolized hope at the inauguration of the twentieth century, electric utilities can again be a guiding light for improving our quality of life.

## Next Steps in the Transition

We started this paper with the statement "speculation abounds about the long-term results of competition and deregulation, and the degree to which either will occur." Just before we finalized this paper for publication, in April, the California Public Utilities Commission announced it was abandoning the traditional cost-ofservice ratemaking and exploring competitive market options, including retail wheeling. Hearings will begin during the summer of 1994.

This announcement was played up by the California news media. Many stations carried special segments, with the message that this announcement was the forerunner of a transition like that of deregulation of telecommunication monopolies. There were some special reports on the options *all* customers would have, such as selecting their own provider and accessing new features. New features, like smart house technologies, would also be linked with the "information highway" as we enter a brave new world. Rather than reporting this as a change for utility companies, the news media focused on exciting new technology options for residential customers.

As we note in our paper, regulatory experimentation and uncertainty about rules, or lack thereof, will be the predominant theme of resource planning over the next few years. Customers, utilities, other service providers (NUGs and ESCOs), and regulators are all anticipating change, but with a variety of expectations. California is but the first of other states who will reassess their regulatory policies. The only certainty at this point is that tremendous changes are possible, and that planners will be called upon to make decisions in the face of this uncertainty.

### Endnotes

- 1. As just one of many examples, the California Public Utilities Commission's first and only Biennial Resource Plan Update, begun in 1990, has taken four years and has not yet concluded.
- 2. However, not all of the identified and contracted NUG resources in California are expected to be built. Prices and terms will change at the end of the initial ten-year period. Some 25%-50% of these resources may never be built or may be abandoned. Biomass and geothermal units, which typically have high operating costs, are the NUG resources most at risk.
- 3. Carroll, Lewis. Alice in Wonderland. 1865.
- Of the winning bids, 28% (5,193 MW) are now in operation, 11% (2,052 MW) are under construction, 43% (8,140 MW) are still in development, and 18% (3,442 MW) have been delayed or canceled, according to *Current Competition*, Vol. 3, No. 2, May 1992; and Vol. 4, No. 1, February 1993.

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