Local Integrated Resource Planning: A New Tool for a Competitive Era

Local integrated resource planning is a new planning approach that can provide more informed business decisions, resulting in higher transmission and distribution asset utilization, lower overall costs, and enhanced customer service. Experience garnered from utilities on four continents illustrates the potential of this new approach to reduce capital expenditure for T&D and reduce risk in a time of rapid industry change.

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The competitive restructuring of the electric power industry is intensifying pressures for electric utilities to control costs through improved utilization of existing assets and by minimizing capital investment in new transmission and distribution (T&D) capacity. Local integrated resource planning (LIRP) is a new planning approach being explored by growing numbers of electric utilities to reduce capital expenditures by deferring or avoiding expensive transmission and distribution investments. In this regard it has shown great promise, in some cases cutting expenditures by two- to ten-fold. LIRP also offers other benefits, however, that have not been as widely recognized—notably, improved utilization of existing grid and generation assets, reduced vulnerability to conflicts over T&D siting, reduced risk in a time of rapid industry change, and an opportunity to gain valuable experience with distributed generation and storage resources.

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The LIRP approach offers another, little recognized benefit: It expands the knowledge of the true cost of supplying electricity to a particular area at a specific time. This information would be vital should a utility wheel power from another supplier to a retail customer, or for an independent system operator (ISO) that uses locational pricing either in a wholesale pool spot market, or in retail competition. As William Hogan recently stated in these pages, "With everyone paying the true locational marginal cost prices, there is no averaging and no cost shifting" among users of the grid.[1]

Its most profound contribution, however, may be the cultural change LIRP helps to foster. At the core of the LIRP approach is a focus on the customer and how the customer's energy service needs can best be met, as opposed to the more traditional approach of using centralized generation as the starting point for planning, with transmission and distribution options as the sole means of delivering a commodity product—electrons—to customers. By reorienting the way utilities think and plan, LIRP can assist utilities in the fundamental transition to a customer-driven industry.

As evidence of the large potential for capital savings, Ontario Hydro (OH) estimates that three recent LIRP projects are expected to avoid conventional investments valued at C$730 million by spending some C$149 million on a host of distributed resource and revised T&D investments. The options typically considered under LIRP include customer-based energy efficiency improvements, load control, local generation and storage, fuel switching, alternative rates, and targeted T&D reconfiguration and investments.

About 100 LIRP-type analyses have been or are being conducted by North American utilities,[2] including Central Power & Light, Consumers Power, and New York State Electric & Gas. In countries where competition in the electric power industry is further advanced than in North America, such as Australia, Ireland, New Zealand, Sweden and the United Kingdom, utilities also are pursuing LIRP-type projects. Although the specifics vary, one common theme emerges: LIRP can deliver effective solutions, often at less than half the expense of conventional planning approaches.

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As is normal with most new ventures, not all of the LIRP-generated projects have been unconditionally successful. For utilities, there remains the difficulty and expense of collecting detailed customer load data and the danger of simply basing a project on incorrect assumptions. And as with forecasting weather, the smaller the target, the harder it is to predict. Careful analysis, incorporating ample margin for error, and the generation of regularly updated load forecasts to guarantee that a particular program is on target, are crucial to achieving a project's goals. Some utility practitioners also believe that better analytical tools are needed in order to reduce the difficulty of undertaking a LIRP approach.

The most significant barrier to using LIRP, however, seems not to be the scarcity of easy-to-use analytical tools or the increased cost of undertaking a LIRP analysis, but the cultural reorientation that this approach requires. Conducting a successful LIRP project requires various utility departments that are not normally accustomed to communicating with each other to work closely together with a common purpose. Utilities will need to pay close attention to these cultural changes in order to capitalize on the potential benefits LIRP offers.

I. Case Studies of Local Integrated Resource Planning

The use of LIRP-type planning essentially started in the 1990s, yet already a large number of utilities have begun to explore the option. Most have used the approach for a single pilot project in order to evaluate its potential, though a number of utilities are beginning to adopt it on a more extensive scale. The following case studies

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provide a broad look at the wide variety of ways LIRP has been used thus far. Three common themes emerge from these examples:

1. LIRP can provide significant cost savings in T&D spending;
2. LIRP requires an intensive information-gathering effort at the onset in order to evaluate customer uses and needs; and
3. LIRP can be applied in urban, suburban, and rural settings, and in a wide variety of countries where utilities are adapting to increasing competition.

A. Ontario Hydro

Ontario Hydro (OH) launched its first LIRP project in the Collingwood area of Ontario in April 1993. Located 120 kilometers northwest of Toronto, Collingwood is a major center of tourism, with a number of large ski resorts and weekend homes. The area had been experiencing rapid electrical load growth—about seven percent annually as recently as 1990. By the winter of 1992-1993, residential heating and snowmaking loads were driving weekend peak loads to 164 MW, or within 95 percent of supply line capacity. In the words of the utility's planners, "There was . . . a great urgency to provide new [transmission] capacity."[3]

Ontario Hydro's planners initially took a conventional approach and examined building a new 230 kV transmission line to supplement the existing 115 kV line, and a 230/44 kV transformer station to the two existing 115/44 kV stations by 1999. The estimated cost of the new facilities was C$83 million.[4]

The economic recession of the early 1990s dampened growth forecasts dramatically, however, to an estimated one percent per year. OH took a second look at its plan for Collingwood as concerns arose that the new facilities would not generate a fast enough return on the investment.

Using a LIRP process, OH's planners formulated an alternative strategy of demand-side measures (including curtailable rates), T&D upgrades, and portable generation. Total cost of the LIRP-generated plan is estimated to be C$24 million. The demand-side measures that were proposed included load shifting residential water heating, improving lighting efficiency, and postponing the operation of industrial furnaces.[5] OH specifically aimed at measures that would "maximize the kW [peak] reduction while minimizing the kWh [use] reduction,"[6] as the utility did not want to cut revenue. Implementation has started (water heater controllers started being installed in the summer of 1995), with customer-focused measures expected to reduce demand by 13 MW of peak capacity by 2000—enough, the utility thought, to meet the area's incremental needs until 2006.[7] The revised T&D upgrades, which consist of constructing 37 kilometers of 44-kV feeders, would provide another 9 MW of relief, and meet the area's needs until the year 2009.

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In 1995, however, OH undertook a review of the Collingwood line, and it found that voltage problems caused the line to be derated by roughly 10 MW.[8] Faced with a shortage of transmission capacity, the utility chose to initiate part of the revised T&D upgrades planned for the next decade. Before that decision, the bottom line from this LIRP analysis was to defer the original C$83 million T&D expansion through the year 2009 by investing C$24 million on local resource and T&D measures. (Revised economic calculations have not been developed.)

In addition to the Collingwood project, OH has more than a dozen other LIRP studies underway or completed, the largest in Toronto.[9] In order to meet Toronto's summer daytime peaks which were expected to become critical after 1999, OH had plans on the books to spend some C$400 million on conventional T&D upgrades. A reevaluation of the plans, however, found that a combination of distribution reconfiguration and demand-side meas-

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ures yielded a proposed solution for C$100 million, saving C$300 million—as well as the headaches associated with obtaining approval for new transmission and distribution facilities in densely populated areas. The LIRP process also uncovered a need for OH to conduct a load retention program targeted at commercial cooling loads.[10]

In another case, OH found that simply initiating the LIRP process revealed that the original problem was not as significant as earlier assessments indicated, and that previous plans to upgrade T&D systems were not required.[11] Overall, OH credits its use of LIRP with having deferred or canceled some C$1.7 billion in T&D spending through August 1995.[12] With the benefits becoming clearer, LIRP is now the standard method of T&D and customer service planning at the utility. As one OH distribution planner states, "LIRP has become our business."[13]

B. Consumers Power Co.

During the summer of 1993, Consumers Power (CP) experienced a series of nighttime T&D failures leading to loss of power at a resort community called Sandy Pines, 15 miles from Grand Rapids, Michigan.[14] On July 2, a distribution switch burned up, cutting power. Two nights later, a conductor burned down just outside a substation. On July 6, another jumper burned out when the area's 5,000 kVA transformer experienced a load of 6,577 kVA. In August, another switch burned up. CP responded by adding a second feed to the resort, but the company delayed constructing a new substation to see if an LIRP approach could solve the problem more economically.

CP staff first visited Sandy Pines to identify what was driving the nighttime peak loads. They found that the area's residents would generally return home from group evening activities in their on-grounds electric golf carts at roughly the same time. Once home, most of the residents would plug in their carts for battery recharging. The combined load pushed demand above the feeder's capacity. Once CP discovered the problem's cause, it then tested whether charger load control could reduce the peak loads, and it followed the positive results with a survey of residents to determine whether they would be amenable to participating in such an effort. Based on the survey, CP launched a pilot project to test the charger load control concept in July 1994.

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The outcome of the trial encouraged CP. The load factor on participants' circuits improved significantly, to 0.589 compared to 0.488 for nonparticipants during the summer of 1994, leading to a much smoother load profile.[15] Most important to the utility, participants did not experience the large, late-evening peak associated with battery recharging over the July 4 weekend in 1994, a signal that the peak load had been reduced. Overall, CP anticipates reducing peak load, but with no real change in kilowatt-hour consumption among customers using the load charger controller, thereby maintaining the same revenue stream for the company.[16] CP confirmed these results through additional tests that took place during the summer of 1995,[17] and the company has delayed the construction of a new $1.5 million substation indefinitely.

C. New York State Electric & Gas Corp.

In April 1993, the New York State Electric & Gas Corporation (NYSEG) established an interdepartmental task force to examine the feasibility of integrating targeted DSM and local generation into T&D planning.[18] The task force drew up screening requirements to identify potential projects, initially coming up with 38 proposed system upgrades. Subsequent screenings winnowed the list to the most appropriate one for a pilot project, a transmission upgrade in the Long Lake Area in Adirondack State Park. NYSEG

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had plans to erect a new substation and lines there at a cost of $6.2 million in order to reduce the roughly 20 annual outages the area was suffering by the early 1990s.

NYSEG staff first undertook a careful analysis of what was driving local peaks and outages. Only then did they examine the many alternatives to the T&D upgrade—from targeted DSM and direct load control to expanding local generation (a 2,000 kW diesel generator already provided backup power, but summer and winter peaks exceeded its capacity). The utility found that the most cost-effective solution was to offer interruptible rates to one large user, the Adirondack Historical Association (AHA), which draws 11.5 percent of the circuit's load (much of it to run air conditioners in the Association's museum), coupled with the utility's dispatch of the AHA's two 300 kW back-up generators at times of peak demand. The communications and metering hardware for connecting the AHA generators to the grid cost $45,000, far below the $6.5 million earmarked for the original T&D solution. After purging commissioning bugs, the system was up and successfully operating in the summer of 1995.[19]

D. Central Power and Light/ Central and South West Corp.

Right up against the Mexican border, at the edge of Central Power and Light's territory, is the second fastest growing city in the United States (after Las Vegas, Nevada): Laredo, Texas. Peak electricity load in Laredo also is growing rapidly, at more than six percent (or 15 MW) annually. In response, CPL anticipates spending some $106 million on transmission and distribution upgrades over the next decade, in addition to the $17 million transmission line project already filed for with state regulators.[20] To reduce these expenditures, and the resulting rate impact on all the utility's customers, CPL has initiated an effort to examine how local measures in Laredo could slow down summer peak growth.

To no one's surprise, CPL discovered that air conditioning was driving peak load. The utility also found, through an extensive analysis of the margin between cost of service (based on detailed load profiles) and sales revenue for different end uses, that air conditioning provides little or even negative margin for the company.[21] (See **Figure 1**.)

CPL responded to this information by formulating a peak load

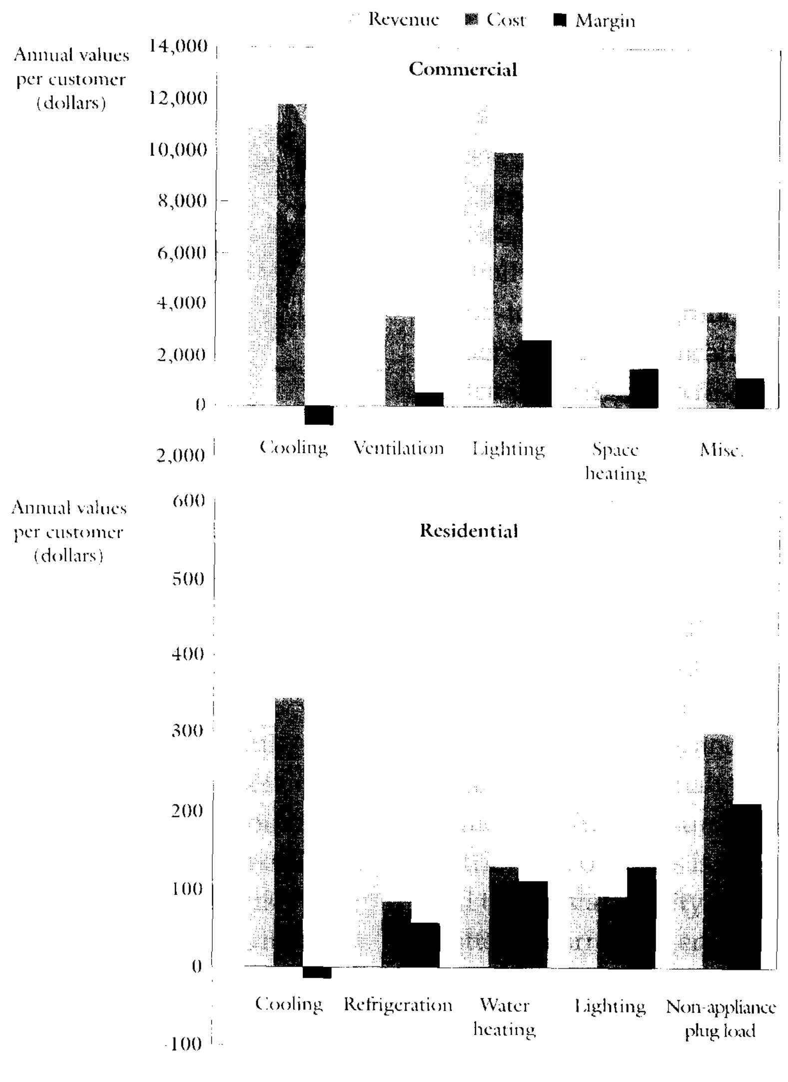

Figure 1: Average Revenues, Costs, and Margin by Selected End Use for the Commercial and Residential Customers in Laredo, Texas.

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reduction program that could provide "as much as a $7 million increase in CPL margin over a 10-year period," according to Chris Greenwell, Director of Rates and Regulatory Affairs at Central and South West Services (like CPL, a subsidiary of Central and South West Corp.).[22] In contrast to the above case studies, CPL's effort to shift load in Laredo includes not just traditional load control measures where the utility "pulls the switch" to turn off and on air conditioners or electric water heaters. CPL's plan also includes the use of innovative pricing schemes, including time-of-use (TOU) and real-time pricing (RTP). RTP in particular allows customers to voluntarily cut power use during periods of peak demand, rather than be locked into a preset schedule that TOU might entail.[23] The residential component using RTP is part of Central and South West Service's Customer Choice and Control project, which by 1996 already had connected 900 homes (of some 2,500 planned) with fiber-optic cable to a utility communications network.[24]

CPL anticipates acquiring three to four MW of load reduction in Laredo from pricing programs in 1996. The goal includes as much as three MW from large commercial accounts, 1.5 MW from commercial users of thermal energy storage systems, and around one MW from residential customers. If the goals are met in 1996, CPL plans to expand its initiative in subsequent years.[25]

Utilities in other parts of the world also have successfully employed LIRP approaches to defer or avoid T&D upgrades. In the United Kingdom, Manweb has completed one LIRP project in Holyhead,[26] and has two other LIRP projects underway, at Crewe and Knowlsley.[27] Other utilities in the British Isles, including SEEBOARD and Scottish Hydro Electric, are using the approach,[28] as is the Electricity Supply Board of Ireland.[29] Stockholm Energi also has completed a major LIRP study in downtown Stockholm.[30] Distribution utilities in New Zealand,[31] including Southpower Limited, Power New Zealand, and Mercury Power, have explored LIRP options, as have Australian utilities.[32] Finally, LIRP is being adopted for use in developing countries, with the World Bank considering support for a project underway in Minas Gerais, Brazil.[33]

II. Cultural and Organizational Change

John Fox, Executive Vice President and Managing Director of Ontario Hydro's Customer Services Group, describes the cultural evolution required for successful LIRP as follows:

> The past paradigm has been while all the load occurred at the meter, it was essentially planned for at the generator. Utilities were driven by aggregating expectations of load demand and making decisions for capital investment based on when to sequence new generation, and then build the requisite transmission and distribution to disperse it. … The demand-side had to be modeled as a piece of generation. In doing so, the modeling ignored all the nongeneration benefits of DSM. … We asked ourselves: 'What happens if you reverse the planning process and start at the demand-side?' … What you get is an entirely different set of variables to use to solve your problems, and almost inevitably, at lower cost, with shorter lead time, and tailored to the specific needs of the customer.[34]

To make this transition successfully, utilities may find it helps to integrate the departments involved with customer service, sales, local transmission, and the distribution grid under one roof, and then to assign this new department the responsibility to lead future utility planning. At the very least, a key to LIRP is to ensure that these players all communicate and address the T&D bottleneck with the common purpose of providing customer service at minimum cost. It is crucial to have a champion within the organization who can catalyze such a reorientation.

At Ontario Hydro, distribution planning personnel initially were skeptical of LIRP, but the skepti-

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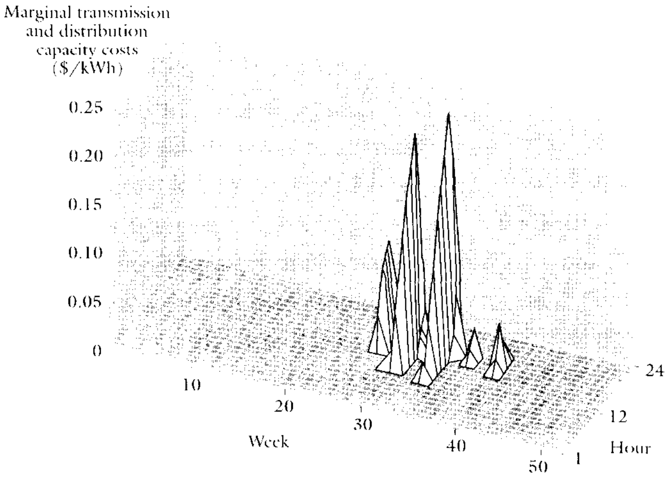
cism began dissipating once distribution planners realized two key points: distribution supply expansion is driven by a specific area demand peak rather than a system-wide peak (which may or may not be coincident); and a proposed T&D upgrade sometimes can be eliminated or deferred through enacting local measures targeted at a specific location for a specific time (See **Inset 1**).

Ontario Hydro planners follow a four-step process for a LIRP analysis. This process has proved to be workable for staff previously trained in a different approach. The steps are similar to

Inset 1: More Accurate Cost Analysis Makes Local Integrated Resource Planning Possible

The growth in activity has been partly underpinned by recent analytical advances that now allow utilities to determine area- and time-specific costs in their service territories accurately. They do so by applying area- and time-specific marginal costs (ATSMC) rather than the more traditional system average of marginal capacity costs and marginal energy costs. The benefit to utilities is that "area-specific costing work allows the precise targeting of programs in areas where the avoided costs are relatively high."[1]

ATSMC does this by capturing the temporal fluctuations in system-level generation and transmission capacity costs, plus the marginal costs of distribution and local transmission capacity (MDCC). (See Figure below.) The MDCC calculation ignores past investments, treating them as sunk costs. Instead, MDCC focuses on future costs, particularly near-term ones, associated with system upgrades. Thus, in order to estimate MDCC, utilities are required to develop a local distribution plan that includes the area's future load growth and related investments in capacity expansion.[2] Utilities typically create such a plan on an annual basis, though not at the detailed level nor with the expanded time frame (20 years or more) required to generate the MDCC for a full ATSMC analysis.[3]



Marginal capacity costs per kilowatt-hour for one midwestern utility. In this example, the peak period encompasses the year's 100 highest hourly loads, all of which occur during the afternoon hours of the summer and early fall.

Once the utility has determined the MDCC, it can establish the comparative value for measures that reduce load, whether local generation, load control, or price signals (for example, real-time pricing). The downside to ATSMC analysis is that the process is data-intensive and analytically demanding, and at least initially, more expensive than conventional planning.

Alternative analytical methods also are being developed for distributed resource and T&D option planning. Others have employed a "Decision Analysis" approach that through a decision tree process is aimed at addressing the uncertainty, flexibility, and riskiness of different alternatives.[4] Unlike an ATSMC analysis, which starts with a predetermined set of marginal (or avoided) costs that are used to assess alternatives, Decision Analysis does not have a preset plan that drives the selection of the preferred path. Rather, a preferred path selected using Decision Analysis transparently and dynamically incorporates decision makers' values and preferences, rather than adjusting costs to drive subsequent decisions.

Even with the more costly approach of ATSMC analysis, long-term benefits should outweigh these costs if planners accurately determine customer energy use, load profiles, and effectiveness of measures undertaken. Not only is there the large potential to save on T&D capital expenditures, but determining ATSMC and MDCC could become an important tool for utilities in pricing T&D capacity to wholesale and retail wheelers of power, and for future Independent System Operators (ISOs) determining locational pricing.

Notes:

1. Joel Swisher and Ren Orans, *A New Utility DSM Strategy Using Intensive Campaigns Based on Area Specific Costs*, Proceedings of the ECEEE Summer Study: the Energy Efficiency Challenge for Europe (Stockholm: European Council for an Energy-Efficient Economy, June 1995).

2. *Id.*

3. Electric Power Research Institute (EPRI), *Technical Assessment Guide (TAG): Distributed Resources1995* (May 1995) EPRI TR-105124, v. 6, at 4-8 to 4-11.

4. Jonathan A. Lesser, Green Mountain Power, *Economic Analysis of Distributed Resources: An Introduction*, presented to Distributed Resources 1995: EPRI's First Annual Distributed Resources Conference, Kansas City, MO (August 29-31, 1995).

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those used by other utilities employing local measures to defer T&D investments and can provide a model for utilities just beginning to consider LIRP.[35]

Problem definition. Utility planners look at the local level to identify constraints that already or soon will hinder the T&D system's ability to meet forecasted load growth. (Utilities already perform this analysis on a regular basis, though in a more simplified version than under a LIRP approach.) The focus is usually on areas experiencing low to modest growth that will require upgrades in a two- to seven-year time frame.

Option development. If problems are identified, planners develop a menu of viable options to address the specific bottlenecks. Included in such options are local generation and storage, T&D investments, customer efficiency measures, rate options, fuel switching, and load management steps. This multiple option approach differs from the conventional perception that the only solution is to increase grid capacity.

Plan development, assessment, and selection. Options are put together into a set of candidate plans, and then characterized by specific attributes (including cost, reliability, environmental consequences, and socioeconomic impacts). A preferred plan is selected, based on a multicriterion assessment, then rechecked by analysts using more subjective methods—a sort of "sanity" check—before being implemented.

Short-term action plan. Implementation then occurs, focusing on those short-term measures that need to be undertaken to meet the objectives of the preferred plan. Included in this step is obtaining utility, government, and partner (who is often the customer) approval for the plan. Once implementation commences, planners regularly review the progress of the measures undertaken through monitoring and the creation of updated load forecasts, so that the preferred plan can be revised if significant changes occur. This last step is crucial to ensure success of the overall effort.

III. T&D Budgets, Asset Utilization and Growing Competition

Much of the initial rationale for LIRP comes from the need for utilities to cut budgets in the face of growing competition. In contrast to budget cuts in most areas of their operations, however, investor-owned electric utilities' capital expenditures for transmission and distribution have continued at a high, and relatively constant, rate. In the United States in 1988, they surpassed generation spending for the first time in 20 years, and by 1994, had reached $11.7 billion, according to preliminary estimates from the Edison Electric Institute (**See Figure 2**).[36] Looking to the future, it is likely that electric utility generation budgets will remain smaller than T&D expenditures.

Additions and upgrades to transformers, switches, and wires usually are undertaken to maintain the utility's ability to meet local peak load demands reliably—loads which occur for relatively few hours during the year. One re-

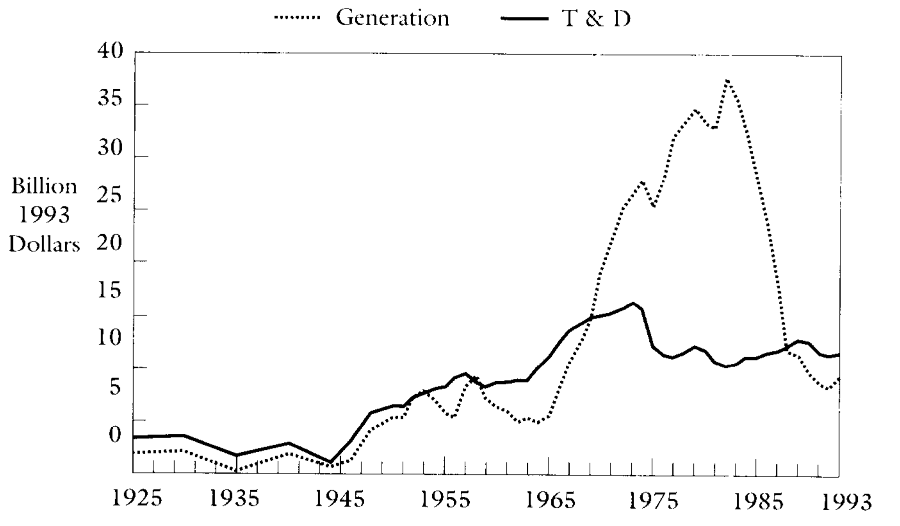

Figure 2: U.S. Investor-Owned Electric Utility Investments in Generation vs. Transmission and Distribution (1925-1993)

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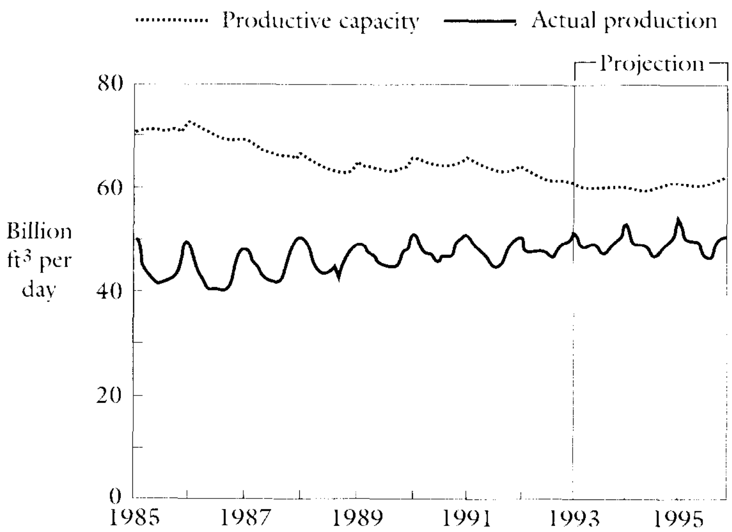
sult is that the load factor for T&D system assets lags far behind that of generation. At Pacific Gas and Electric (PG&E), generation asset utilization never falls below 50 percent, while the typical distribution circuit is used below 50 percent capacity more than 60 percent of the year, and is used at or above 70 percent capacity less than 10 percent of the year (See **Figure 3**).[37]

Asset utilization likely will improve as increased competition comes to a heavily regulated business such as the electric power industry. At least this is what the experience of the U.S. natural gas industry has demonstrated over the past decade.

With the production and distribution of natural gas in the United States now being dictated by market economics, rather than by a handful of pipeline operators who were overseen by regulators, utilization of industry assets has risen substantially. Average wellhead capacity utilization in 1993 was estimated to be 81 percent, far above the 67 percent utilization in 1985, according to the U.S. Department of Energy (see **Figure 4**).[38]

Figure 4: Asset Utilization in the U.S. Natural Gas Industry (1985-1992)



Among the most recent changes in the natural gas industry that will strengthen the trend of improved asset utilization are: the continued development of hubs for buying and selling gas; the implementation of a secondary market in pipeline capacity rights, which allows pipeline customers to trade capacity rights among themselves through the use of electronic bulletin boards provided by the pipeline companies; and a continued increase in storage capacity, which has already led to less month-to-month variation in production and contributed to more efficient use of existing capacity.[39] Many of these measures are similar to those being debated for the electricity market. The bottom line is that as market forces—rather than regulators—increasingly drive decisions in the electric industry, the industry will become more efficient in

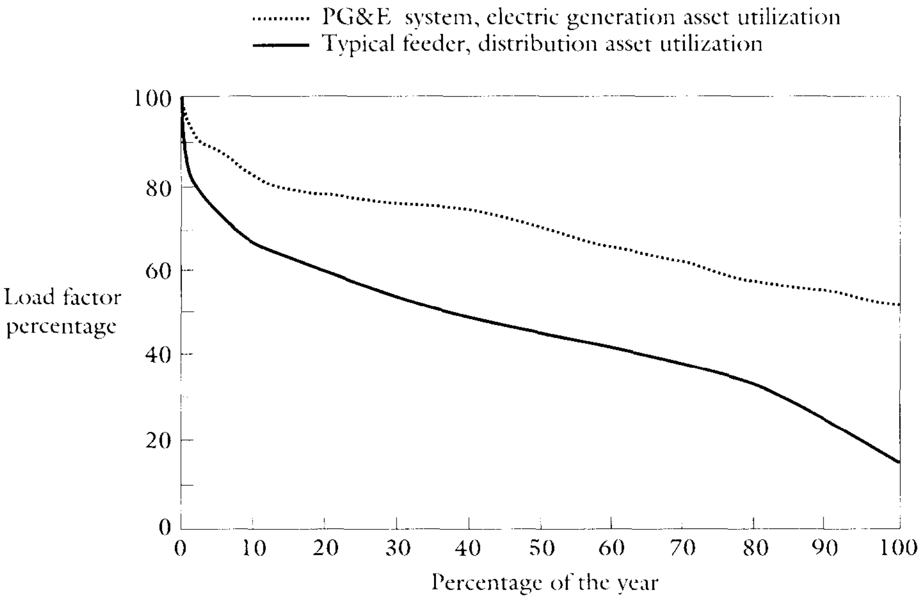


Figure 3: Annual Load Duration Curves for a Typical PG&E Distribution Feeder vs. Entire Generation System

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spending capital and utilizing assets.

IV. Additional Benefits

As the transition to a more competitive market and the acceptance of an ISO utilizing locational pricing proceeds, the flexibility and benefits of LIRP are likely to continue attracting new adherents. The potential benefits, however, extend beyond improved asset utilization and reduced T&D spending. As both Ontario Hydro and Central and South West have found, LIRP analyses can be used to retain profitable, or shift unprofitable, load.

LIRP also can be used by utilities to focus on more complete customer service. This may occur in two ways. Once a utility starts using LIRP as the start of its planning process, the utility can produce marketing, customer service, and sales plans that are more consistent with its distribution plans. This also increases the likelihood of producing a coordinated interface and a consistent relationship with customers.

Then, instead of examining the options along a specific feeder, a utility can use the LIRP approach to examine the needs of a specific customer—and how to meet them. The utility ends up providing the customer with improved service, and hopefully stronger incentive to remain that utility's customer. With an eye toward competition, Ontario Hydro has started employing LIRP-type thinking with its large customers, with the goal of better individualizing the utility response to customer needs.[40] Given such benefits, LIRP may be immediately relevant to utilities, despite the uncertainty they face regarding their long-term structure and competitiveness. ■

Endnotes:

1. William W. Hogan, *A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy*, ELEC. J., Dec. 1995, at 35.

2. Personal communication with Jeff Williams (former DUV Project Coordinator, National Renewable Energy Laboratory, Golden, Colo., and based on an unpublished study conducted as a collaboration of Pacific Gas and Electric, Electric Power Research Institute, National Renewable Energy Laboratory, and Pacific Northwest Laboratory) (June 6, 1995).

3. R.F. Chow and P.S. Owens, Collingwood Targeted DSM Project: Inception to Program Design (Ontario Hydro, Sept. 27, 1994, rev'd Aug. 1995) (presented to the Canadian Electrical Ass'n, Distribution System Planning Conference #15, Ottawa).

4. *Id.*

5. *Id.*; personal communication with Robert F. Chow, Customer Service Planning, Ontario Hydro (June 26, 1995).

6. *Supra* note 4.

7. Laurie Klein, Customer Service Planning, LIRP Projects: Update Ontario Hydro, Nov. 1995, at 1.

8. Personal communication with Robert Chow, Customer Service Planning, Ontario Hydro (March 19. 1996).

9. Enza Cancilla, Customer Service Planning, LIRP Project Update, Ontario Hydro, April 1996, at 1-8.

10. J.P. Toneguzzo, R.F. Chow, G.A. Sperou, Keith Brown, B.K. Horii, and R. Orans, Local Integrated Resource Planning of a Large Load Supply System, presented to the Canadian Electric Association, Transmission and Station Planning & Operations and Power System Reliability Subsection, Power System Planning and Operating Section, Engineering and Operating Division, Vancouver, B.C. (March 1995).

11. Personal communications with Gary Schneider, Customer Service Planning Dept., Ontario Hydro (June 13 and August 28, 1995).

12. John Fox, statement at Distributed Resource 1995: EPRI's First Annual Distributed Resource Conference, Kansas City, Mo. (Aug. 29-31, 1995).

13. *Supra* note 11.

14. Matthew Bombery and Todd R. Duncan, *Consumers Power Delays New Substation Construction by Controlling Electric Cart Battery Chargers*, PROCEEDINGS OF THE DA/DSM CONFERENCE (San Jose, Calif., Jan. 1995)(session 3-1).

15. Personal communication with Matthew Bombery, Consumers Power Co., Northwestern Region, Grand Rapids, Mich. (July 24, 1995)

16. *Supra* note 14.

17. Nick Hall, Sandy Pines Electric Golf Cart Charger Control Program Evaluation, Consumers Power Co., Jackson, Mich. (March 1996).

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18. Kirk C. McAllister and Michael G. Lewis (N.Y. State Electric & Gas Corp.), *Dollar Savings Methods for Traditionalists and Dreamers: A Case Study of Applying DSM for T&D Benefits*, PROCEEDINGS: DELIVERING CUSTOMER VALUE: 7TH NATIONAL DEMAND-SIDE MANAGEMENT CONFERENCE (June 1995), EPRI TR-105196, at 194-99. NYSEG does not use the term LIRP, but the approach appears to be similar.

19. Personal communications wiht Michael Lewis, N.Y. State Electric & Gas Corp., Binghamton, N.Y. (July 24 and Sept. 12, 1995, and March 19, 1996)

20. Chris Greenwell, Central and South West Services, *Designing Profitable Rate Options Using Area- and Time-Specific Costs*, PROCEEDINGS: DELIVERING CUSTOMER VALUE: 7TH NATIONAL DEMAND-SIDE MANAGEMENT CONFERENCE 290-94 (EPRI TR-105196, June 1995).

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