An Overview of the History of Electric Generation Expansion in the United States

Kris Zadlo
Commonwealth Edison Company
P.O. Box 767
Chicago, IL 60690

Brad Teeters, Rajiv Kumar
Robert Cravens and Brian Manhire
School of Electrical Engineering
and Computer Science
Ohio University, Athens, OH 45701

***Abstract*--The forces driving electric generation expansion have changed considerably since the high growth years following World War II. This paper reviews the reasons for this change. In addition, the current status of generation planning in the United States is described. Projections for changes in the electric utility industry are considered through the year 2004.**

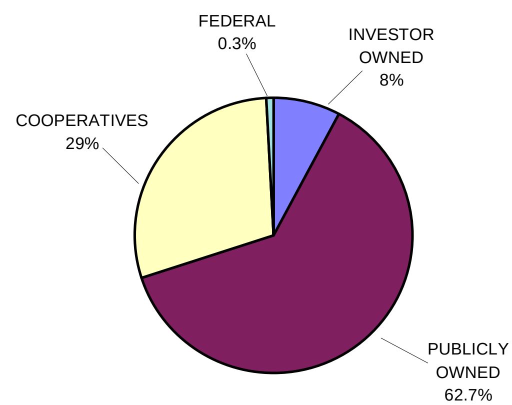
I. INTRODUCTION

Unlike many other countries, the electric power industry in the United States (U.S.) does not consist of a single federally-controlled entity. There is no single agency responsible for capacity planning and day-to-day operation. Instead, there is an electric utility industry in the U.S. that consists of thousands of individual entities operating independently to varying degrees.

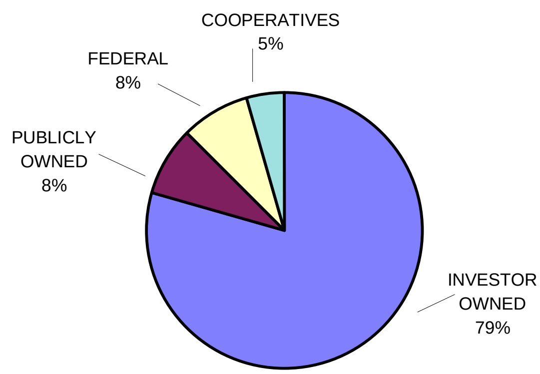
II. UTILITIES BY TYPE OF OWNERSHIP

As shown in Fig. 1, of more than 3,200 electric utilities recognized in 1994, the majority (62.7%) were publicly-owned by states, counties, municipalities or other governmental bodies serving the public interest. An example would be the Department of Water & Power for the city of Los Angeles, California. The second largest group in number (29%) consists of cooperatives that typically provide electric service to rural areas, where population density is low.

The third largest group in number (8%) is the investor-owned utilities (IOU's). The IOU's accept the obligation to provide an adequate and reliable supply of electricity to anyone within the territory they serve,



Total number of entities - 3204
Fig. 1. Number of U.S. electric utilities by type of ownership
Source: U.S. Energy Information Administration Financial Statistics 1994



Total 1994 generation - 2911 Billion kWhrs
Fig. 2. Generation of U.S. electric utilities by type of ownership
Source: Energy Information Administration Electric Power Monthly

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in exchange for the opportunity to earn a profit on their investments (called "the regulatory compact"). Further, they must accept regulation by public service commissions at the state level. These commissions have oversight and rate setting authority to ensure that the supply is adequate and reliable and rates are fair and reasonable.

The federally-owned or supported electric utilities are few in number and principally sell wholesale power to other types of utilities for resale, instead of dealing directly with consumers. Originally, these agencies were formed with the primary emphasis on projects such as dams and reservoirs for flood control and irrigation; with the production of electricity as a secondary consideration. An example of a federally-owned electric utility is the Tennessee Valley Authority.

In terms of number of utilities, the public-owned and cooperative utilities would appear to dominate the industry; however, this is misleading. Actually, as illustrated in Fig. 2, the investor-owned utilities, though comprising less than 10% of the total number, generate nearly 80% of the electric energy produced in the United States. In fact as a group, they typically supply significant portions of generation to the various public-owned and cooperative utilities, which often have no generating capacity of their own. Instead, the publicly-owned and cooperative utilities buy bulk power wholesale from the IOU's and resell it at retail to their customers.

As mentioned previously, there is no central authority responsible for either the operation or growth of the electric power industry. However, there is the Federal Energy Regulatory Commission (FERC). Its primary function is to review and authorize capacity and energy transaction agreements between utilities and wholesale customers to prevent unfair pricing practices. Since the enactment of the 1992 Energy Policy Act, the FERC has been vigorously promoting a free and competitive marketplace. It is this legislation that is currently shaping the electric power industry.

Generation planning, both short and long term, has been generally the ultimate responsibility of the individual utilities, or in some cases, a power pool comprised of several utilities. In a free and competitive marketplace, it is unclear who will bear the responsibility of maintaining appropriate resources in the future.

III. HISTORY

After World War II, the electric utility industry in the U. S. grew dramatically. From the post-World War II years of the 1940's through the 1960's, peak load growth, for the nation as a whole, averaged more than 7% per year for this period. This sustained growth required a doubling of generating capacity about every 10 years. By the late 1960's and early 1970's, the industry was having difficulty maintaining the level of capacity additions required to satisfy this ever increasing demand in an economical and environmentally acceptable manner [1]-[5]. Fig. 3 shows the growth in demand and installed reserves through the year 1994.

The post-World War II years through the 1960's were a period of stable fuel prices, low inflation and technological improvements. Larger central generating stations became cheaper to build on a per kilowatt basis (referred to as "economy of scale") and cheaper to operate, due to decreasing heat rates. During this period, the addition of a new generating unit to a utility often resulted in a lower cost per kilowatt-hour to the customer which further

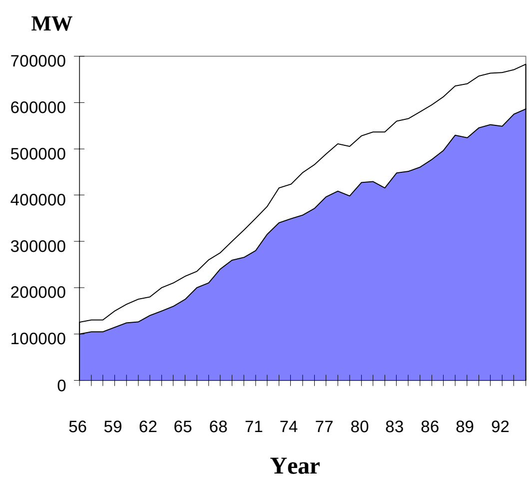

Fig. 3. U.S. electric utility industry annual peak load & reserves
Source: Edison Electric Institute Statistical Yearbook of the Electric Utility Industry

increased demand for output. This in turn caused the cycle to repeat itself. Another development at this time was the rapid growth in the use of air-conditioning, with its associated highly seasonal consumption pattern. Utilities were forced to add generating capacity to meet increased demand. However, the early 1970's also saw a strong increased emphasis on air quality with the passage of the Clean Air Act by the federal government. At this time, many utilities converted their generating units from high sulfur coal, to oil, gas, or low sulfur coal.

Unknowingly, the stage was being set for the severe impact of the oil embargo imposed by members of the Organization of Petroleum Exporting Countries (OPEC) in October of 1973. Almost overnight, the price of fossil fuels began to escalate at unprecedented rates. As these higher costs were passed on to the consumer, electrical energy demand began to decline. However, the majority of utilities believed that the fuel price increase would not be a long-term phenomenon and their commitment to serve all demand remained very strong. This obligation to serve made the risk of falling short of capacity unacceptable when demand eventually rebounded as expected.

However, the escalation of fuel prices did not abate and general inflation affected all aspects of the U.S. economy. The cost to construct new generating facilities began to increase significantly while, simultaneously, rapid increases in interest rates decreased the demand for new housing construction and automobiles, two major components of the total

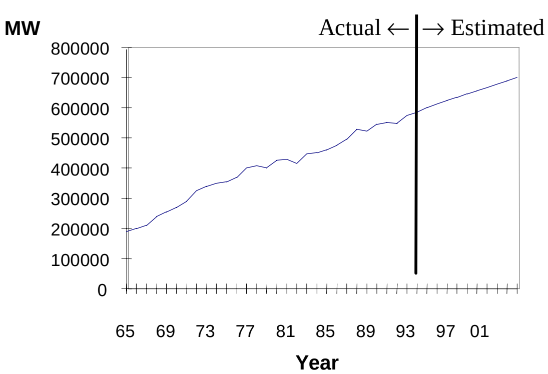

Fig. 4. Non-coincident peak demand for the contiguous U.S.
Source: NERC Electric Power Supply and Demand Reports

economic base and employment in the United States. Rail transportation of fuel (e.g., coal) to the power plant often depended heavily on diesel oil and the price of this fuel tracked the rapid increase in crude oil prices.

After 1974, when the long-range impact of higher energy costs became more apparent, the electric utility industry, as a whole, started adjusting its peak load projections downward. Each year the industry believed matters couldn't get worse, but they did. The decade ended with another oil supply shock and the early 80's ushered in double-digit inflation and one of the most severe business recessions in the years following World War II. It appears that the bottom was reached somewhere in the mid 1980's. OPEC decided that there might be a limit to how much pressure they could exert on the world oil markets because of the basic laws of supply and demand. In addition, non-OPEC oil producers had become a much bigger factor in international oil markets.

In the inflationary period of the 70's and 80's, the long-range aggregate projection of load growth dropped from 7.6% to the current value of approximately 2% per year. Fig. 4 shows the non-coincident peak demand for the contiguous United States. During those intervening years, the reduction in load forecasts resulted in both cancellations of new generating plants and higher than targeted capacity margins as generating plants well under construction began to enter their operational phase. Referring to Fig. 3, this turning point for the industry is evident as the actual load growth dropped and became more erratic after 1973. Installed capacity continued to grow rapidly for several more years as the construction pipeline emptied and utilities adjusted their expansion plans to reflect lower load growth forecasts. During this period, capacity margins swelled beyond the 20% minimum normally required for reliability reasons. As used here, capacity margin is defined as the difference between peak load power and installed capacity available during the peak period. Fig. 5 shows the impact of faltering demand growth as capacity margins rapidly increased to 25% or higher over a very short period.

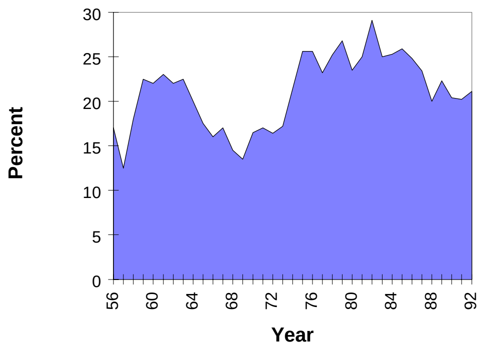

Fig. 5. U.S. electric utility industry capacity margin
Source: Edison Electric Institute Data

IV. FUEL USAGE

The availability of natural resources drives the fuel type used in electrical production. For example, hydroelectric power is a significant source of energy in western and mountain states, where the landscape is mountainous. Oil and natural gas predominate in areas such as the gulf states. However, across the nation as a whole, coal is by far the main source of fuel for electric power generation. Coal reserves in this country are in abundance. It is estimated that the U.S. has one-third of the world's recoverable coal [1]. This suggests that coal will remain the primary fuel source for many years to come. However, a problem with coal is how to combust it in an environmentally acceptable way. Research is currently underway to develop new coal fueled technologies such as fluidized-bed combustion and coal gasification.

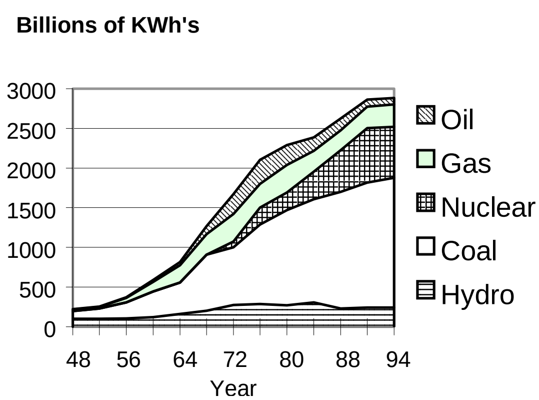

Fig. 6. U.S. electric utilities production by source.
Source: EIA Electric Power Monthly

Fig. 6 shows the U.S. electric utility industry's total production by fuel source for the past 46 years. The growth rate of the electric utility industry by fuel type shows coal as the leader as a result of its great abundance and low cost. Growth in oil and gas occurred because of the impact of stricter environmental laws governing the use of coal. However, growth was stymied by the cost increases that occurred during the oil embargo. Nuclear energy had the potential to capture a much larger share of the market because of its low fuel cost and its environmentally benign characteristics. Uncertainty in regulatory requirements and political issues have increased the financial risk of building a nuclear unit beyond its foreseeable benefits. It is therefore an unlikely option for future planned increases in capacity in the U.S. at this time. The units in operation will continue to run until they are no longer economic to maintain or their (forty-year) licenses expire, at which time many of them will likely be decommissioned due to the high prohibitive cost associated with relicensing. In addition, the lack of long-term spent fuel storage may cause some nuclear units to prematurely shut down. All of the above issues will result in a continual loss in share of energy production by nuclear technology.

Installed capacity by fuel type is presented in Fig. 7. The largest component is coal-fired steam, at 40%. Nuclear and hydro, together, comprises another 24% of total capacity. The balance consists of oil and gas-fired capacity (both steam and combustion turbines), capacity supplied by non-utility generators and miscellaneous - such as geothermal, wind, and solar power. Some of the gas and oil capacity represents units that were originally designed to burn coal, but were later switched to non-solid fuels to meet stricter emissions limits imposed in the early 70's.

Fig. 8 provides a breakdown of the 2,890 billion kilowatt-hours generated by the U.S. electric utility industry in 1994. Both nuclear and coal-fired steam provided a larger share of this energy than their proportion of installed capacity, whereas gas and oil produced considerably less. This result is consistent with the practice of economic operation, which strives to load generating units with the lowest variable cost in preference to more expensive units.

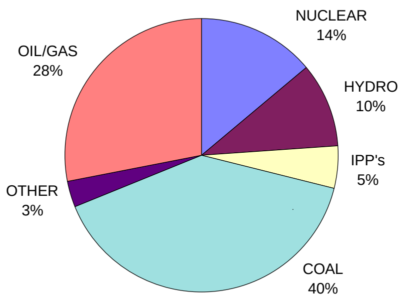

Fig. 7. Generating capacity by fuel type. Estimated 1995 capacity - 703 thousand MW (Summer)
Source: NERC 1995 - 2004 Electric Supply and Demand

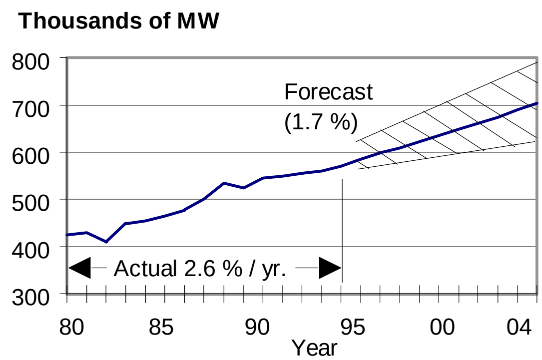

Fig. 9. Projected Summer peak demands through 2004.
Source: NERC 1995 - 2004 Electric Supply and Demand

V. PROJECTIONS FOR THE NEXT DECADE

The forecast for peak load growth through the year 2004 is given in Fig. 9. The industry faced rapid load growth until the early 1970's. Oil shortages and high inflation curtailed peak demand growth through the late 1970's and most of the 1980's. The forecast of peak demand growth through 2004 is provided in Fig. 9. The industry has forecast an annual average growth in peak demand of between 0.7% and 2.7% with an 80% probability (indicated by the cross-hatched area of Fig. 9) the actual rate will fall in this range. The only certainty is that load growth rates are uncertain.

Part of the strategy of the utility industry has been a focused effort to serve whatever demand should develop and avoid shortages of generating capacity at all reasonable cost. Recent history has created a tremendous disincentive to risk the economic future of the industry on forecasting the right energy production technology and building the correct amount of it to serve future demand. Changes in the market, such as the oil embargo, resulted in lower growth in peak demand than had been projected.

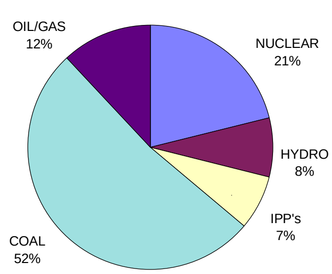

Fig. 8. Generation of U.S. electric utilities by source of energy. Total 1994 generation-2890 billion kWh.
Source: NERC 1995 - 2004 Electric Supply and Demand

The result was the construction of excess capacity through the late 1980's. Regulatory commissions concluded that the electric utility industry should have better predicted market changes. In some cases, they have disallowed portions of the construction cost of new plants and barred recovery of some of the investment from consumers. These decisions have shaken the notion that future demand must be met at all reasonable cost. The economic risk of overestimating demand may have become too great.

The current deregulation of the electric utility industry has added another variable to the generation planning equation. The resulting competition has utilities cutting costs in efforts to become the favored supplier. Failing to be competitive could result in a significant loss of market share. A utility's market share would have to be determined prior to any capacity expansion commitment.

If peak demand growth should follow the middle estimate of 1.7% (Fig. 9), the peak for the year 2000 of 650 GW would require about 780 GW of installed capacity to provide a minimum reserve margin of 20%. Fig. 10 presents an aggregate picture of the U.S. electric utility industry's installed capacity in 2004. A total of 788 GWs is expected to be in service in 2004 which corresponds to an annual average growth rate of 1.2%. With the demand growing faster than the rate of capacity additions (which has been the case for the past several years), the risk of reliability problems is increasing. Further, most of the proposed capacity additions have not been authorized by the utilities or

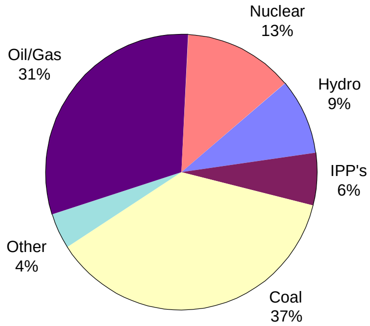

Fig. 10. Capacity resources of U.S. electric utilities by fuel type. Estimated 2004 capacity 788 thousand MW (Summer) Source: NERC 1995 - 2004 Electric Supply and Demand

approved by the responsible public service commissions for construction. In fact, many of the projects are not even in the planning stage so there is a high probability that they may never be built. Presently, the majority of new capacity is being built by Independent Power Producers (IPP's) and not by utilities. Since 1990, IPP's have installed 58% of the nation's new electric capacity [6].

The current thrust (although it is rapidly changing) in generation planning, or as it has been redefined in the last few years as "integrated resource planning," is to first attempt to curtail peak demand growth. Measures such as load management and energy conservation are envisioned as ways to potentially defer the need for new capacity for several years. Load management might consist of remotely operated controls to interrupt on-peak usage such as air-conditioning load to reduce peak demand. Conservation could consist of upgrading building insulation or lighting equipment to improve energy use efficiency. Various plans are currently being proposed to encourage consumers to take the necessary steps to implement such changes, but this process is still in its early stages in many areas of the country.

Although most utilities recognize that such measures may forestall the need for new capacity, but not eliminate it, there has been a bias toward taking low risk paths. In terms of new supply, the predominant approach of most utilities and public service commissions, in descending order of preference appears to be as follows: capacity purchases, life extension, derating recovery, repowering retired units, and new generating units.

Purchases of firm supply from a neighboring utility having a sufficient capacity is the first option, although this becomes less likely an alternative as time passes. Refurbishing older, smaller generating units is very desirable provided environmental laws can be met at a reasonable cost. Recovering capacity through plant improvements also appears attractive when these deratings are significant and recoverable at reasonable cost. Also, bringing smaller retired units back into service, perhaps using coal or natural gas, may be economically attractive.

Ultimately the only remaining choice will be the addition of new generating capacity. Since the utilities that comprise the industry have varying levels of excess capacity, many of them will need to make decisions within the next five years in order to meet demand.

New capacity may take the following forms: combustion turbines, pulverized coal-fired steam, fluidized bed combustion, compressed air energy storage, combined cycle, gasified coal, and nuclear. However, today there is a widespread bias toward shorter lead time options. Furthermore, the uncertainty of deregulation, public acceptance, required licensing and construction times have eliminated the nuclear option in this country for the next decade.

Coal is a logical choice for new generating units, given this country's abundant supply of that fuel. Stricter environmental laws make it a more expensive option than in the past. However, developments in fluidized-bed combustion and coal gasification may make this source of energy more environmentally acceptable. Flue gas scrubbers have also matured in design and shown a good level of reliability, making traditional pulverized coal units candidates for the intermediate or cycling duty often provided by oil and gas-fired units today.

Meanwhile, utilities have responded to demand growth uncertainty and future potential disallowances by public service commissions for overbuilding by shifting the capacity planning process in favor of short lead-time technologies. The goal is to postpone actual construction, as long as possible, until there is more certainty about how utilities will recover the costs of existing generating units under deregulation. In other words, utilities are trying to avoid the risks of "stranded investment." Short lead-time technologies, such as combustion turbines and combined cycle units, rely heavily on either natural gas or oil. Although the prices of these fuels are now reasonably low, there is concern that increasing demand could outstrip supply, causing significant price increases and shortages in the future.

VI. DEREGULATION

In hopes of bringing lower power costs to electric consumers and spurring competition among electric utilities, Congress passed the National Energy Policy Act of 1992 to allow for deregulation of the electric utility industry to occur. FERC's Order Number 888 and Number 889 released April 24, 1996, requires all utilities owning, controlling, or operating transmission lines to file non-discriminatory open access tariffs that would offer others the same transmission service they presently provide for themselves. Among other things, these Orders require fully integrated utilities to functionally unbundle. In essence this will divide an electric utility into separate generation, transmission, and distribution companies.

This means that the current focus of resource planners to meet demand at all cost will change to that of a market type approach. Generating companies will strive to be the lowest cost producers in order to increase profits and market share. Resource planning activities will be market driven rather than demand driven and hence may be unlikely to resemble past practices.

VII. CONCLUSION

No matter what happens over the next several years, a balanced mix of demand-side measures, refurbishment and construction will eventually occur. These new resources will not only be provided by traditional electric utilities but also by IPP's and third parties. The industry remains on a "learning curve" concerning what approach will prove to be the best. The best plans are likely to be those that can weather uncertainty and meet market expectations with the least impact on the future cost of producing electric energy.

VIII. REFERENCES

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