SCENARIOS FOR MEETING U.S. ELECTRICITY NEEDS IN 2030 --

POLICY ISSUES AND INFRASTRUCTURE CHALLENGES

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FOREWORD

Electric Power Group (EPG), LLC prepared this report under the auspices of the Consortium of Electric Reliability Technology Solutions (CERTS)[1]. The CERTS Program Manager is Joseph Eto, Lawrence Berkeley National Laboratory. The project was funded by Department of Energy's Office of Electric Transmission and Distribution, Transmission Research Program, Philip Overholt, Manager, under Contract DE-AC03-76SF00098 Subcontract No. 6496360.

[1] CERTS is currently conducting research with funding from the U.S. Department of Energy (DOE) Transmission Reliability Program and the California Energy Commission. CERTS is working with electric power industry organizations, including ISOs, RTOs, NERC, and utilities. CERTS members include Electric Power Group, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, National Science Foundation, Power Systems Engineering Research Center (PSERC), and Sandia National Laboratories.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Adequate supplies of electricity, reliable operation of the electric grid, and reasonably priced electricity are critical to support the modern digital and information based U.S. economy and meet the economy's needs for higher levels of reliability and power quality. Many regions of the country are grappling with regulatory and market structure to encourage much needed investment in generation, transmission, and technologies to promote reliable grid operations and efficient markets. Lack of investments in electricity infrastructure have contributed to power outages and market dysfunction as was evidenced by the August 14, 2003 blackout in the Eastern Interconnection and problems in California in 2000-2001.

This report focuses on the future electricity power plant and transmission infrastructure needs for the year 2030 under alternative scenarios. The scenarios are not predictions or forecasts. They are designed to outline the substantial infrastructure needs for new power plants and transmission lines under different assumptions. The analysis provides a context for policymakers to address the critical challenges facing the U.S. in assuring adequate and reliable electric supplies. Electricity infrastructure planning has a long lead time. Understanding the implications of these scenarios is critical to develop a common ground to guide U.S. electricity policy.

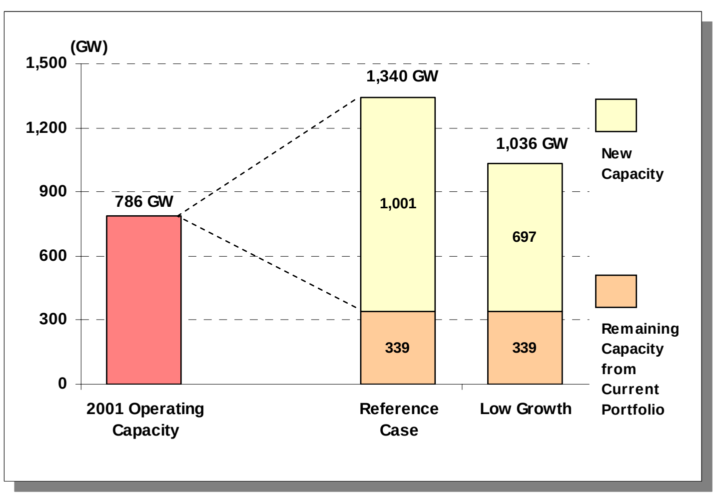
For the target year 2030, U.S. electricity needs under alternative scenarios of load growth and mix of power plants to meet future electricity needs are analyzed. The scenarios are not forecasts or predictions about the actual course of power plant development. The scenarios postulate alternative end states and assess the scenarios in terms of power plant development, energy mix, transmission needs and reliability. Assessment of trends and scenarios indicate that by 2030:

- U.S. population will grow to over 335 million, an increase of 72 million over 30 years;
- Electricity peak demand will be 1,165 GW, an increase of 490 GW from current levels, or an average annual peak demand growth of 1.9%;
- The existing stock of power plants capable of producing 786 GW will decline to 339 GW assuming retirement of power plants 50 years or older;
- Total capacity requirements in the base case are estimated at 1,340 GW, assuming a 15% reserve margin. To provide adequate electric supplies for the U.S. economy this translates to 1,000 GW of new power plants to replace retired power plants and meet load increases;
- Requirements for new power plants are estimated at 700 GW under a low growth scenario;
- Increasing non-hydro renewables to 5% of energy will require a nearly tenfold increase in firm on-peak renewable capacity from 14 GW to 131 GW;

- In all scenarios, gas consumption for electricity production increases from a modest 15% to as much as 450% if no new coal or nuclear plants are built.

Several alternative scenarios for load growth and mix of power plants to meet needs in 2030 are outlined. The first scenario examines a gas dominated future with increase in renewables to 5% of energy mix. The second scenario assumes an increase in coal and nuclear proportionate to load growth. Other scenarios assume higher level of renewables, moderate growth in gas consumption, lower load growth due to lower economic growth or higher levels of customer owned distributed generation or high conservation or some combination of the above factors. All scenarios assume substantial increase in renewables from current levels. Scenarios are compared qualitatively in terms of key attributes such as capital cost, operational cost, price volatility, environmental impact, and potential operational integration issues. The estimate of power plant need in the high and low load growth scenarios is summarized in Figure A. Some of this need may be met by life extension or repowering at existing sites.

Figure A
Scenarios for U.S. Need for New Capacity By 2030



Need for New Capacity:

- **1001 GW in Reference Case**
- **697 GW in Low Growth Case**

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The resulting capacity and energy mix under the alternative scenarios is summarized in the Figures B and C. The first scenario – *Current Trend*, results in a future dominated by gas power plants. Electricity production from gas plants increases eightfold from 2001 levels. This is clearly unsustainable. Increasing coal and nuclear to maintain their proportion of installed capacity at today's levels (approximately 50%) results in a 65-70% increase in currently installed capacity. This may not be publicly or environmentally acceptable. Meeting all future needs with renewables is infeasible – even increasing renewables contribution to 10% of energy mix with low growth scenario will be a challenge as it translates to a fifteen-fold increase in firm capacity and sevenfold increase in energy production. The last scenario with low growth, substantial increase in renewables and modest increases in gas, coal, and nuclear offers a diversified and balanced approach to meet future electricity needs.

Figure B
Capacity Mix Under Each Scenario
- GW -

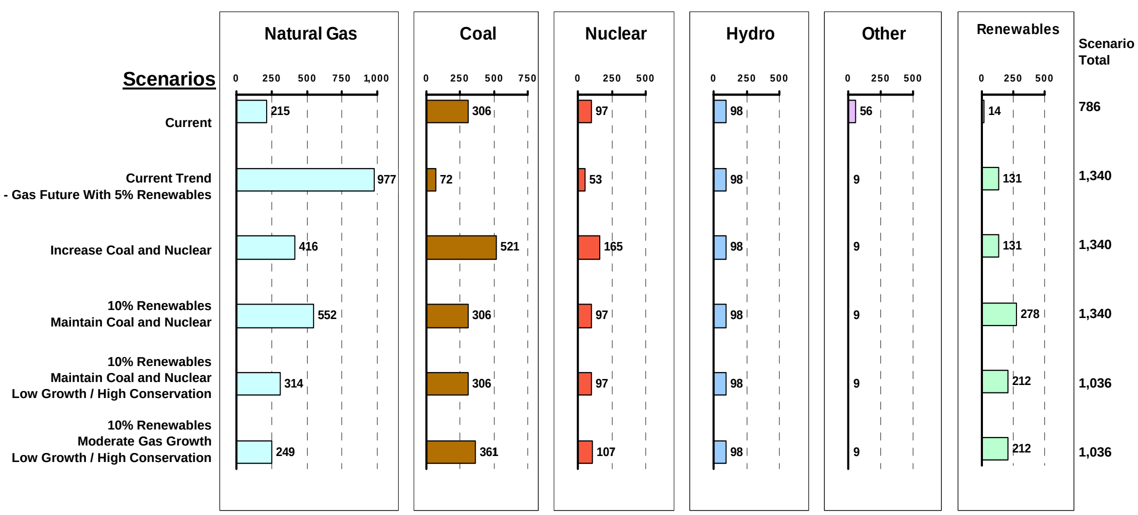

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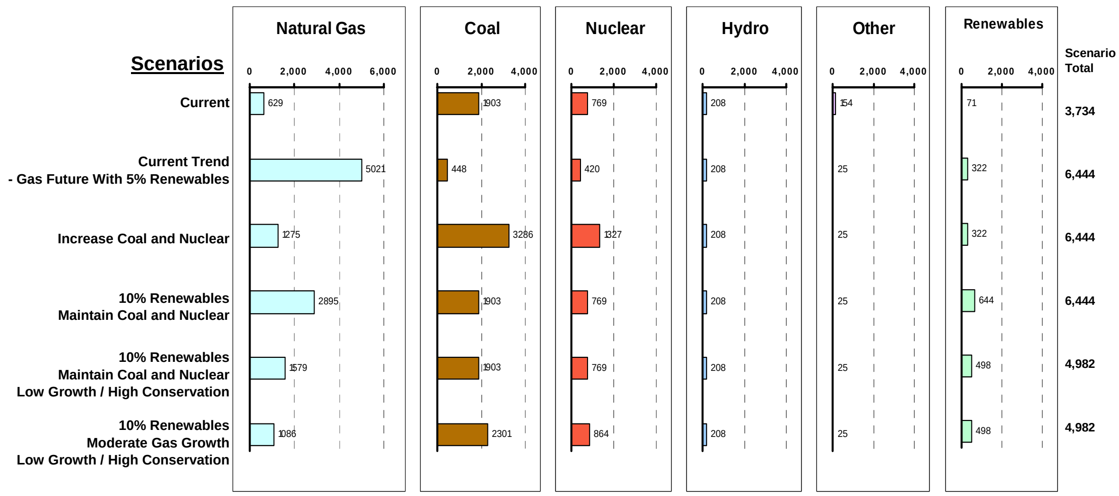
Figure C
Energy Mix Under Each Scenario
- billion kWh -



Building 700 to 1,000 GW of new power plants to meet U.S. electricity needs in 2030 has significant implications for the nation's transmission grid. The current bulk power transmission system consists of 157,000 miles of 230 kV and above and connects 786 GW of generating power plants. Adding 700 GW to 1,000 GW of new power plants over the next 30 years will require interconnections, transmission upgrades, new technologies, as well as new corridors for transmission lines. An initial assessment of the number of sites required indicates that some where between 1,900-3,400 new power plant sites will be required. If new transmission needed is proportionate to current generation and transmission infrastructure, 140,000 to 200,000 circuit miles of additional transmission will be required in the low growth and base case scenarios. However, policy choices regarding location and size of power plants could significantly impact the transmission infrastructure requirements. Also, newer technologies and better utilization of existing transmission assets could substantially reduce needed new transmission.

In planning for the transmission interconnections for the future, the U.S. has to look ahead 25 to 30 years to allow adequate lead time for corridor planning, transmission rights-of-way, and coordination among states and utilities. Most of the existing transmission was planned 30 to 40 years ago. Major new transmission projects have ten year or longer lead-time. Generation projects are being planned on a much shorter lead-time. Hence, there is no reliable information on new power plant locations to guide long range transmission planning. Yet, if the long term transmission planning issues are not addressed, the opportunity to site needed new transmission interconnections may be lost or become prohibitively expensive, just as in the case of building new freeways or airports in population centers. Also, if transmission planning is reactive, there is a risk of stranded generation, increased congestion, bottlenecks, and degradation of reliability.

The current grid has to be transformed into a smart network with investments in new technologies, new power plants, and transmission lines have to be added for load growth and to replace aging power plants. It is critical to plan for future transmission corridors from resource rich regions or locations where power plants are likely to be sited to market hubs and load centers. Resource rich regions that offer abundant renewable and coal energy need to be connected to load centers to enable power plant development in these regions. Additionally, the transmission grid of the future must be dynamic, connect and integrate new generating resources, be able to self-adjust for contingencies and meet the local area reliability needs. These long-term needs present major policy challenges and steps need to be taken now to assure an adequate, robust, and secure electricity infrastructure.

This report presents alternative scenarios not as a prediction of the future but to provide an assessment of impacts of alternative scenarios as a tool to guide long-term energy policy. The scenarios are designed to provide a context for the critical long-term policy issues and infrastructure challenges facing the U.S. in assuring adequate and reliable electric supplies over the next 30 years.

SCENARIOS FOR MEETING U.S. ELECTRICITY NEEDS IN 2030 – POLICY ISSUES AND INFRASTRUCTURE CHALLENGES

INTRODUCTION

The August 14, 2003 Eastern Interconnection blackout has once again focused attention on the reliability and adequacy of the U.S. electricity infrastructure.

Adequate supplies of electricity, reliable operation of the electric grid, and reasonably priced electricity are critical to support the modern digital and information based U.S. economy and meet the economy's needs for higher levels of reliability and power quality. The importance of the electric industry and need to address the infrastructure challenges have been recognized by the President and the Department of Energy.

National Energy Policy Plan: The President released this plan in 2001. The National Energy Policy Development Group recommendations focus on the need to remove constraints, bottlenecks, and infrastructure deficiencies in the transmission grid to enable electric supplies to meet the growing needs of the economy.

National Transmission Grid Study (NTGS): The DOE released the NTGS in May 2002. The study emphasizes the need to remove bottlenecks to ensure reliable and affordable electricity now and in the future. The study also noted the need for investments in new technologies and improved operating practices to improve utilization of existing infrastructure.

There are significant reliability and market operations issues that have emerged from the Eastern Interconnection blackout (2003), dysfunctional California market (2000-2001), and concerns about bottlenecks and market gaming in virtually every region of the country. Many regions of the country are grappling with regulatory and market structure issues to encourage much needed investment in generation, transmission, tools and technologies to promote reliable grid operations and efficient markets. Lack of investments in electricity infrastructure has contributed to power outages and market dysfunctions which are very costly for the U.S. economy.

This report focuses on the future electricity power plant and electricity infrastructure needs for the year 2030 under alternative scenarios. The scenarios are not predictions or forecasts. They are designed to assess the substantial infrastructure needs for new power plants and transmission lines under different assumptions. The analysis provides a context for policymakers to address the critical challenges facing the U.S. in assuring adequate and reliable electric supplies.

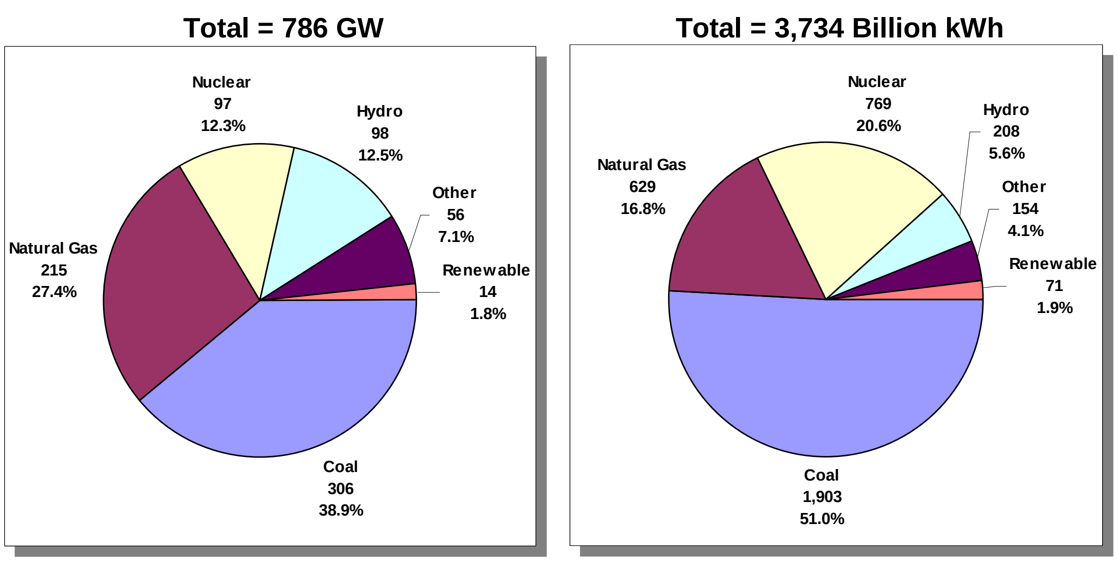
U.S. ELECTRICITY SYSTEM

The U.S. electricity system is made up of generation, transmission, and distribution infrastructure. The operation of the power system is managed through control areas operated by utilities, transmission companies, ISOs and RTOs. There are approximately 135 control areas and six ISOs/RTOs in operation with several additional in various stages of formation. The industry continues to evolve to a market based structure with independent transmission and generation companies.

Power Plant Capacity

The U.S. power plant generation capacity in 2001 was 786 GW and produced 3,734 Billion kWh of energy. Coal plus nuclear account for over 50% of the installed capacity and over 70% of the energy mix (see Figure 1).

Figure 1
U.S. Generating Capacity and Energy Mix - 2001



Capacity Resources (GW, %)* **Energy (billion kWh, %)**

Source: Energy Information Administration (EIA), Electric Power Annual 2001 (DOE/EIA-0348 – 2001). March 2003

* Additionally, the EIA reports 46,700 MW of Stand-by capacity and 6,300 MW of Out of Service capacity (non-operational units for Summer 2001) for a total of 840,400 of Installed Capacity. 8,000 MW of new additional generation capacity came online by the end of 2001

Notes: 1) **Natural Gas** includes Waste Heat cogeneration from Gas Generators. 2) **Hydro** includes Pumped Storage capacity. 3) **Other** includes Petroleum and Other Gases. 4) **Renewables** include Wood, Waste, Landfill, Biomass, Geothermal, Solar and Wind.

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Nearly 68% or 532 GW of the existing capacity was built prior to 1980 and will be 50 years or older by the year 2030. An additional 20% of capacity was built during the 1980s and will be 40 years or older by 2030 (see Figure 2). Excluding hydro, 447 GW or 57% of existing capacity will be 50 years or older by 2030. There are over 13,500 generating units currently operating. Over 8,000 of these units were built prior to 1980 and will be 50 years or older by 2030. Excluding the nearly 3,000 generating units that are hydro, over 5,000 units will be 50 years or older by 2030.

Figure 2
Age Distribution of Current U.S. Generating Capacity In 2030

Capacity (GW)	Coal	Natural Gas	Nuclear	Hydro	Other	Renewable	Total
50 years and older (in service on or before 1980)	234	120	44	85	47	2	532
40 to 50 years old (in service during 1981-1990)	62	18	51	10	3	7	151
less than 40 years old (in service during 1991-2001)	10	77	2	3	6	5	103
Total Capacity Resources	**306**	**215**	**97**	**98**	**56**	**14**	**786**

No of Generating Units	Coal	Natural Gas	Nuclear	Hydro	Other	Renewable	Total
50 years and older (in service on or before 1980)	1,197	2,015	55	2,928	1,951	167	8,313
40 to 50 years old (in service during 1981-1990)	211	700	46	717	364	543	2,581
less than 40 years old (in service during 1991-2001)	72	1,165	2	184	601	596	2,620
Total	**1,480**	**3,880**	**103**	**3,829**	**2,916**	**1,306**	**13,514**

- **532 GW will be 50 years or older by 2030**
- **Excluding hydro, 447 GW will be 50 years or older**

Source: Energy Information Administration (EIA), Electricity Generation Capacity – Form EIA-860 Database (Annual Electric Generator Report)

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Power Plant Capacity Additions

Between 1991 and 2001, 103 GW of new power plant capacity has been added. Almost 75% of this capacity is fueled by natural gas (see Figure 3). The capacity of gas fired power plants increased to 27% of total in 2001, compared to 20% ten years earlier. Renewable capacity increased by 5 GW during the last decade, an increase of over 50% from the installed base in 1991. However, renewables still account for less than 2% of total capacity. As a percent of total U.S. capacity, hydro, coal, and nuclear all declined. On a going forward basis, the U.S. has to consider investments in new power plants that produce electricity from a diversified mix of sources including renewables, coal and nuclear, as an all gas future is not sustainable.

Figure 3
Capacity Additions During 1991-2001

	Capacity Installed on or before 1990		Capacity installed from 1991 thru July, 2001		Summer 2001 Capacity Resources	
	GW	%	GW	%	GW	%
Coal	296	43.3%	10	9.7%	306	38.9%
Natural Gas	138	20.2%	77	74.8%	215	27.4%
Nuclear	95	13.9%	2	1.9%	97	12.3%
Hydro	95	13.9%	3	2.9%	98	12.5%
Other	50	7.3%	6	5.8%	56	7.1%
Renewable	9	1.4%	5	4.9%	14	1.8%
Total	683	100.0%	103	100.0%	786	100.0%

- 103 GW of capacity was added, an increase of 15%
- 75% of capacity added was from gas-fired power plants

Source: Energy Information Administration (EIA), Electricity Generation Capacity – Form EIA-860 Database (Annual Electric Generator Report)
* Natural Gas Includes capacity from Waste Heat Cogeneration Units

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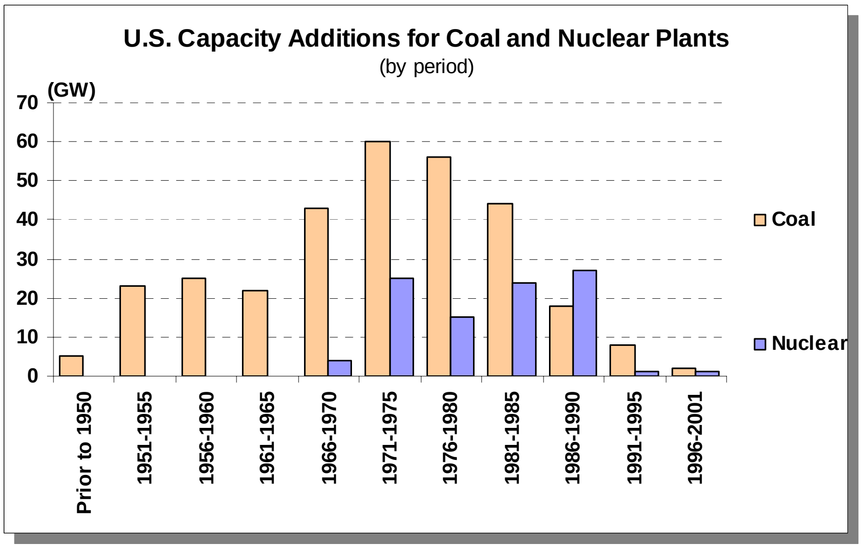
In the last decade, no significant capacity has been added from coal and nuclear fueled power plants (see Figure 4). The addition of new coal capacity peaked during the early seventies and has since been declining steadily.

Figure 4
U.S. Coal and Nuclear Capacity Additions By Time Period



In the last decade:

- **There were no significant coal additions**
- **Only two new nuclear plants came online (Comanche Peak and Watts Bar)**

Source: Energy Information Administration (EIA), Electricity Generation Capacity – Form EIA-860 Database (Annual Electric Generator Report)

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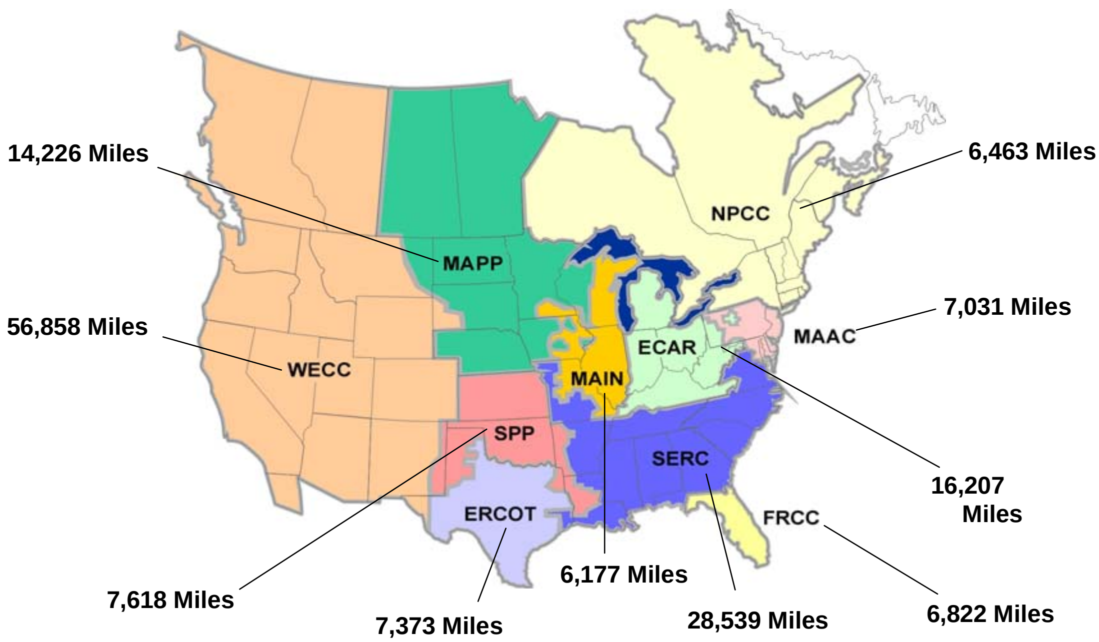
Transmission System

The U.S. high voltage transmission infrastructure, 230 kV and above, comprises over 157,000 circuit miles (see Figure 5). This high voltage system serves as the backbone to facilitate transfer of electricity from power plants to customers, as well as for interregional transfers to support competitive wholesale markets. Approximately 35% of this transmission is in the Western interconnection, 5% in ERCOT, and the balance 60% in the Eastern Interconnection spread over eight different reliability regions. In the Eastern Interconnection, five reliability regions each have approximately 5% of the total U.S. transmission (NPCC, MAAC, FRCC, MAIN, and SPP), two reliability regions have approximately 10% of the total U.S. transmission (MAPP and ECAR), and SERC is the largest with approximately 20% of the total U.S. transmission.

Figure 5
U.S. High-Voltage Transmission
230 kV and Above



* 2001 data – NERC ES&D database

Total 157,314 Circuit Miles

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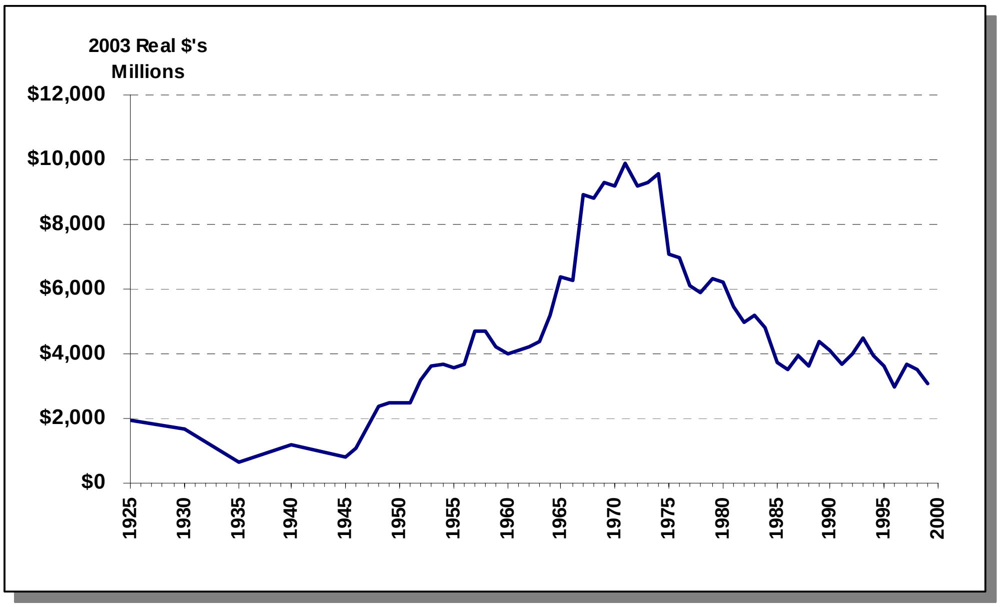
Figure 6 shows the history of investments in transmission in 2003 dollars. As can be seen, the investments peaked at approximately $10 billion/year in the mid-70s and have declined to the $4 to $5 billion per year in the last decade. This underinvestment is resulting in degradation of reliability and network carrying capacity as evidenced by congestion, bottlenecks, and stranded generation. Transmission infrastructure investments are needed to expand, upgrade, and modernize the grid, as well as add intelligence and real time wide area monitoring and control capabilities using digital, power electronics, silicon and software technologies.

Figure 6
U.S. Expenditures in Transmission 1925-1999
(Real 2003 $'s Millions)



Source: *How Will the Blackout Shape the Future of T&D?* Steven Brown. Utility Automation & Engineering T&D. Vol. 8, #5, September 2003.

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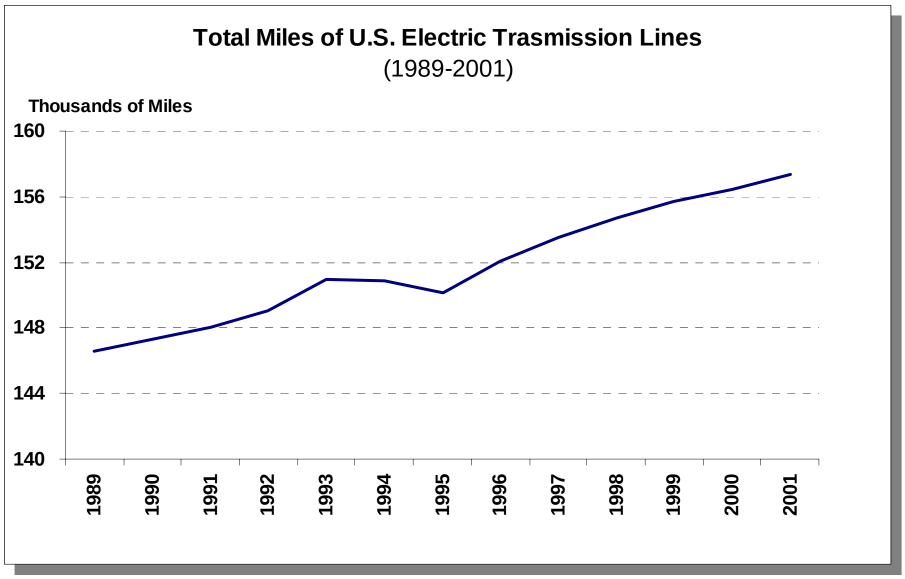
Much of the high voltage transmission system was developed in the 60's-70's to connect major remotely located generating power plants to load centers. Like the generation power plants, the transmission infrastructure is also aging and a bulk of it will be 50 years or older by the year 2030. The issue for an aging transmission system is not the fact that the wires will stop conducting or that the towers will collapse, but the fact that the 50 year old technology does not have the intelligence in terms of control, communications, sensing equipment to operate as a smart dynamic grid needed for emerging wide area regional competitive markets. The growth of the transmission system from 1989 to present is shown in Figure 7. Approximately 90% of the bulk power transmission grid was built prior to 1990. Transmission infrastructure investments have lagged the growth in generation. For example, in the last decade approximately 10,000 miles of high voltage transmission has been added – an increase of approximately 6%. During the same comparable period, the generation additions represented a 15% increase and load growth was approximately 20%.

Figure 7
U.S. Bulk Power Transmission –
230 kV and Above Circuit Miles



Source: 2001 data – NERC ES&D database

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OUTLOOK FOR POPULATION AND ECONOMIC GROWTH

The United States had 262.8 million people in 1995. Based on a U.S. Bureau of Census projection, the U.S. population will reach 335.1 million by 2025, a net increase of 72.3 million over a 30-year period. International migration to the United States is projected to be around 24.7 million, approximately one-third of the nation's population growth over the 30-year period.

Based on Annual Energy Outlook (AEO) 2003 prepared by the EIA, the U.S. economy as measured by gross domestic product (GDP) is projected to grow at an average annual rate of 3.0 percent during the 2001 to 2025 period.

OUTLOOK FOR ENERGY SUPPLY

U. S. domestic natural gas production is projected to increase from 19.5 trillion cubic feet in 2001 to 26.8 trillion cubic feet by 2025. Domestic natural gas production is increasingly dependent on unconventional and more costly conventional resources both onshore and offshore in the lower 48 states. As the demand is larger than the domestic supply, an increasing share of U.S. gas demand will be met by imports from Canada, Mexico, and imported liquefied natural gas (LNG).

The AEO projects that net imports of natural gas will increase from 3.7 trillion cubic feet (16% of total demand) in 2001 to 7.8 trillion cubic feet (22% of total demand) in 2025.

U.S. coal production is projected to increase from 1,138 million short tons in 2001 to 1,440 million short tons by 2025. Net coal exports are expected to fall throughout 2001 to 2025 period.

Electricity generation from natural gas, coal, and renewable resources is projected to increase as demand for electricity continues to grow. Natural gas used for electricity generation is forecast to have the highest annual growth rate. The share of natural gas in the generation fuel mix increases from 17% in 2001 to 29% by 2025, an annual growth rate of 4.2% over the period.

The share from coal decreases from 52% in 2001 to 48% in 2025 although the AEO assumes that 70 GW of new coal-fired capacity will be constructed during the period 2001 to 2025. No new nuclear capacity is forecast and, hence, the share from nuclear decreases from about 20% in 2001 to 14% by 2025.

Estimated recoverable U.S. coal reserves as of 2001 were around 5,500 quadrillion Btu and sufficient for 255 years at the 2001 level of consumption[2]. Over 50% of estimated U.S. recoverable coal reserves are in the Western United States. One-third of 2001 U.S. coal production was from Wyoming, with Montana the second leading coal producing state in the country. Coal is plentiful and, on a delivered basis, cost an average of $1.25/MMBtu in 2001 compared to natural gas in the range of $4 to $5/MMBtu.

Total U.S. natural gas reserves at the end of 2001 were 189 quadrillion Btu, i.e., less than 4% of current U.S. estimated recoverable coal reserve energy value, and sufficient to sustain only 8 years of consumption at the 2001 level. On the average, the U.S. natural gas reserve increases by approximately 22.6 quadrillion Btu per year, which is very close to the current level of consumption. However, the AEO projects that the annual consumption of natural gas will reach 35 quadrillion Btu by 2025. The AEO projects that 22% of year 2025 demand will be satisfied by imports and national gas reserves will decline to less than 5 years of consumption.

[2] Coal reserve quantities are 2001 recoverable coal reserves at producing mines, estimated recoverable reserves, and demonstrated reserve base as reported by the EIA in the Annual Coal Report, 2001.

There will be upward pressure on natural gas price as the remaining supply decreases over time. Price volatility will also increase. The impact of these factors on electricity price volatility and implications for long-term generation and transmission planning should be recognized.

The increase in consumption of natural gas cannot be sustained from domestic U.S. and Canadian imports. Total natural gas reserves of these two countries are less than 5% of worldwide reserves. An increasing share of U.S. natural gas consumption will be met by imports, including LNG.

There are four existing U.S. LNG import facilities. Capacity expansion plans have been announced by three of these facilities. The AEO projects that imports will reach 22% of total demand in 2025 and that LNG will be an important share of these imports. In addition, the planned construction of an LNG terminal in Baja California will add natural gas supplies for new power plants planned in Mexico and California. For electricity imports, the United States needs to look at resource- or generation-rich regions such as electricity generated from LNG in Baja California and Canada.

Renewable resources will play an important role in supplying the United States' growing electricity needs through development of additional wind, solar, geothermal, and biomass resources. There is potential to substantially increase the contribution of renewables from the current level of 2% excluding hydro and 8% including hydro.

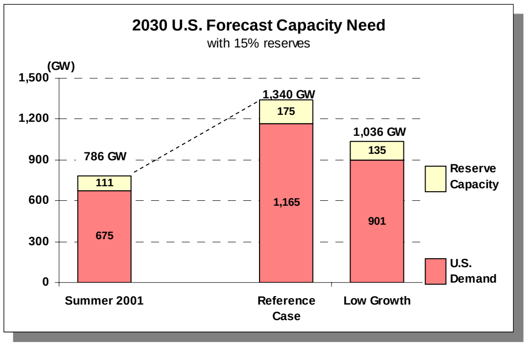
ELECTRICITY NEEDS IN 2030 – ALTERNATE SCENARIOS

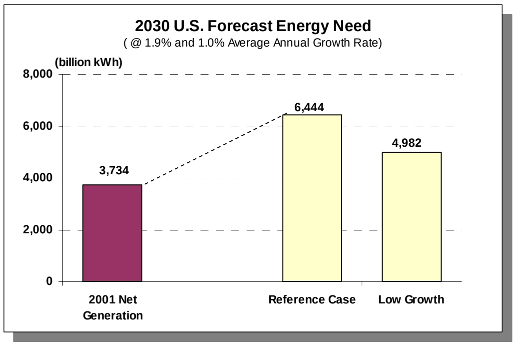
During the 1990's the average annual demand growth in the U.S. was 2.2%. On a going forward basis forecasts from NERC and EIA indicate a load growth of 1.9% per year. However, the actual load might be substantially lower as a result of greater contribution from investments in energy efficiency, conservation, demand management – both price responsive and direct load control, distributed generation at customer locations or due to lower economic and population growth. In this study, a 1% year annual growth is assumed for such a low growth scenario.

The summer peak demand in 2001 was is 675 GW. At 1.9% demand growth, this will grow to 1,165 GW by 2030. Assuming 15% planning reserve margin, the total required installed capacity would be 1,340 GW. Under the low growth scenario, peak demand is forecast to be 901 GW and the required installed capacity is estimated to be 1,036 GW (see Figure 8).

Figure 8
Scenarios for U.S. Capacity and Energy Needs by 2030

- **Reference Case** – 1.9% annual average growth based on EIA and NERC Forecasts
- **Low Growth** – 1.0% annual average growth due to higher energy efficiency and demand management or lower economic and population growth





*Source: NERC Reliability Assessment 2002-2011. October 2002

**Source: Energy Information Administration (EIA), Electric Power Annual 2001 (DOE/EIA-0348 – 2001) March 2003

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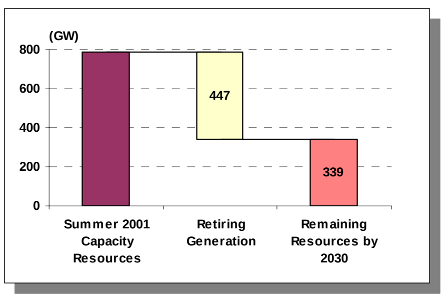
POWER PLANT REQUIREMENTS AND NEED FOR NEW CAPACITY BY 2030

Power plants are typically designed to operate for 30 years; however, with life extension and refurbishment many power plants operate for 50 years. For this analysis, it is assumed that all power plants over 50 years, except hydro, will be retired. Consequently, by 2030, 447 GW or 57% of the currently available power plants will no longer be operational. The retired capacity will include 234 GW of coal or 81% of the current coal capacity, and approximately 50% of the currently operating nuclear and natural gas fired power plants will be retired (see Figure 9). With these retirements in 2030, the remaining available capacity from the current mix of power plants will be 339 GW.

Figure 9
Remaining Power Plant Capacity by 2030 Assuming All Power Plants Over 50 Years Old (Excluding Hydro) Retired

- 57% of current capacity will retire by 2030. Retirements will total 447 GW.
- 81% of currently operating Coal Plants, 53% of Nuclear Plants, and 52% Natural Gas power plants will retire by 2030.



	Retiring Capacity (GW)	Energy Generation (billion kWh)	No of Generating Units
Coal	234	1,455	1,197
Natural Gas	120	351	2,015
Nuclear	44	349	55
Hydro	0	0	0
Other	47	129	1,951
Renewable	2	10	167
Total	**447**	**2,294**	**5,385**

Retiring Power Plant Capacity by the year 2030

	Remaining Capacity (GW)	Energy Generation (billion kWh)	No of Generating Units
Coal	72	448	283
Natural Gas	95	278	1,865
Nuclear	53	420	48
Hydro	98	208	3,829
Other	9	25	965
Renewable	12	61	1,139
Total	**339**	**1,440**	**8,129**

Remaining Power Plant Capacity in 2030 from Existing Fleet of Power Plants

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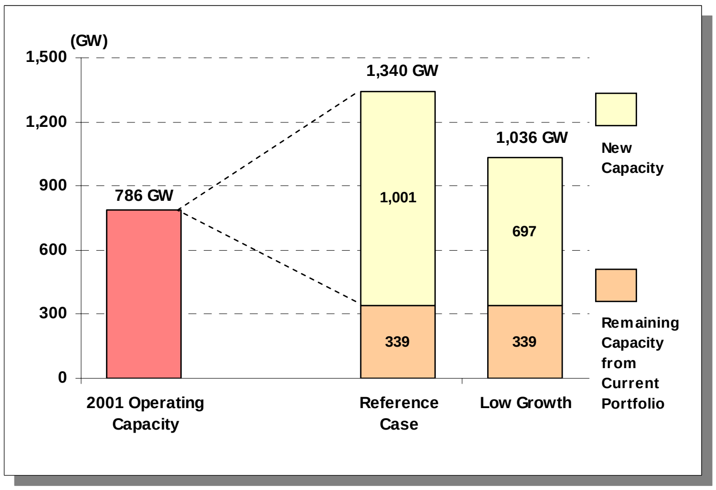
To meet the total installed capacity requirements, about 1,000 GW of new power plants will have to be built over the next 30 years in the base case, and about 700 GW under the low growth scenario (see Figure 10).

Figure 10
Scenarios for U.S. Need for New Capacity By 2030



Need for New Capacity:

- **1001 GW in Reference Case**
- **697 GW in Low Growth Case**

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Some of this need for new power plants may actually be met through life extension, repowering of older power plants, or construction of new power plants at existing sites

DESCRIPTION OF ALTERNATIVE SCENARIOS TO MEET RESOURCE NEEDS IN 2030

Alternative scenarios for power plant development to meet resource needs in 2030 have been developed and their implications examined. In all cases, the amount of renewable energy (excluding hydro) is assumed to increase substantially to either 5% or 10% of total energy, from the current 1.9%. The scenarios include:

Current Trend – Gas Future with 5% Renewables
Increase Coal and Nuclear
10% Renewables, Maintain Coal and Nuclear
10% Renewables, Maintain Coal and Nuclear, High Conservation
10% Renewables, Moderate Gas Growth, High Conservation

These scenarios are not forecasts – they are designed to examine alternative futures, which will inform policy makers in development of a strategy to meet long-term electricity infrastructure needs.

A summary of scenarios is provided in Figure 11.

Figure 11
Alternative Strategies to Meet 2030 U.S. Capacity Requirements

Scenarios	Load Growth	Renewables	Coal / Nuclear	Gas
Current Trend - Gas Future With 5% Renewables	1.9% average annual load growth	New renewables to provide 5% of total energy	No new Coal or Nuclear plants. No refurbishment or life extensions beyond 50 years	Continue to build Gas-Fired power plants as replacements for Coal and Nuclear retiring facilities to satisfy energy and capacity requirements
Increase Coal and Nuclear	1.9% average annual load growth	New renewables to provide 5% of total energy	Replace/repower all coal and nuclear retiring facilities. Build additional Coal/Nuclear facilities to maintain 2001 share levels (53.1% of Capacity Resources)	Build Gas-Fired power plants to satisfy remaining capacity and energy requirements
10% Renewables Maintain Coal and Nuclear	1.9% average annual load growth	New renewables to provide 10% of total energy	Replace/repower all coal and nuclear retiring facilities to maintain capacity at 2001 levels (403 GW)	Build Gas-Fired power plants to satisfy remaining capacity and energy requirements
10% Renewables Maintain Coal and Nuclear Low Growth / High Conservation	1.0% average annual load growth	New renewables to provide 10% of total energy	Replace/repower all coal and nuclear retiring facilities to maintain capacity at 2001 levels (403 GW)	Build Gas-Fired power plants to satisfy remaining capacity and energy requirements
10% Renewables Moderate Gas Growth Low Growth / High Conservation	1.0% average annual load growth	New renewables to provide 10% of total energy	Replace/repower all coal and nuclear retiring facilities. Build additional Coal/Nuclear facilities to satisfy capacity and energy requirements	Limit increase in energy from Gas-Fired power plants to an average 1.9% annual growth.

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The implications of each scenario are discussed below.

Gas Future With 5% Renewables: In this scenario, renewables are assumed to increase to 5% of energy mix, a more than fourfold increase in energy from current levels (71 Billion kWh to 322 Billion kWh) and a nearly tenfold increase in capacity (14 GW to 131 GW). Given the intermittent nature of renewables, the actual installed capacity required maybe two to three times the firm capacity. Remaining needs for load growth and retirements are all met by new gas-fired power plants. In an all gas future, the capacity for gas-fueled generation will increase from 215 GW today to 977 GW of which 882 GW will be new power plants. The energy production from gas-fueled generation will increase from 629 Billion kWh to 5,021 billion kWh, an eightfold increase. Natural gas consumption, assuming higher efficiencies of new gas plants compared to current fleet, will increase to 36 Tcf/year, a fivefold increase from today's levels. Given the declining gas reserves in the U.S. such large increases in gas requirements will substantially increase dependence on world markets, require large number of new pipelines and LNG terminals, and are not sustainable.

Increase Coal and Nuclear:
Under this scenario, renewables are assumed to provide 5% of energy. Coal and nuclear capacity is increased proportionate to load growth to maintain their share of total capacity at 2001 level (53%). This results in total coal and nuclear capacity of 676 GW in 2030, compared to 403 GW today. Coal capacity increases from 306 GW to 521 GW. With coal plant retirements, 449 GW of new coal plants will be needed for growth and replacement of retiring coal units. Nuclear capacity will increase from 97 GW to 165 GW. A total of 112 GW of new nuclear plants will be needed for growth and replacement of retiring nuclear power plants. Coal consumption will increase from 993 tons/year to 1,709 tons/year, almost doubling in 30 years. Of the total new coal and nuclear capacity of 561 GW, approximately half is for replacement of retiring units. Some of this need may be met through life extension or repowering of existing power plants. If existing sites could be fully utilized, it would maximize use of existing infrastructure including transmission, fuel delivery, and water. Natural gas consumption for electricity will increase more modestly, from 7 Tcf to 9 Tcf/year. However, developing new coal and nuclear capacity at existing or new sites presents substantial environmental, social and political challenges.

Ten Percent Renewables and Maintain Coal and Nuclear at Current Levels:
To meet 10% of total energy requirements in 2030 from non-hydro renewables will require renewable capacity of increase from 14 GW to 278 GW. This represents a 20-fold increase in renewable capacity. Given the intermittent nature of renewables, the actual installed capacity required maybe two to three times the firm capacity. Retiring coal plants totaling 234 GW and nuclear plants totaling 44 GW would have to be replaced in kind at existing or new sites. Gas capacity will increase from 215 GW to 552 GW and natural gas consumption will increase from 7 Tcf to 21 Tcf/year – which is not sustainable without substantially increasing dependence on foreign supplies of natural gas.

Ten Percent Renewables, Maintain Coal and Nuclear, Low Growth/High Conservation:
In this low growth scenario, 10% energy from renewables means an increase to 212 GW from the current 14 GW, a 15-fold increase. Coal and nuclear capacity remains at current levels, and gas capacity increases from 215 GW to 314 GW. Gas consumption increases to 11 Tcf, a 70 to 80% increase from current levels. The low growth may result from low economic and population growth, high conservation, demand management, distributed generation, or some combination of these factors.

Ten Percent Renewables, Moderate Gas Growth, Low Growth/High Conservation:
In this scenario, increases in capacity for gas are limited to an average of 1.9%/year growing from 215 GW to 249 GW; coal increases from 306 GW to 361 GW; and nuclear

97 GW to 107 GW. Even with these modest increases, due to retirements, significant new capacity will be needed – 154 GW of new gas plants, 289 GW of new coal plants, and 54 GW of new nuclear plants. Renewables are increased substantially, from 14 GW to 214 GW, a fifteen-fold increase.

Gas consumption increases by approximately 20% to 8 Tcf per year by 2030. Coal consumption increases from 993 to 1,196 thousand tons/year.

COMPARATIVE ASSESSMENT OF SCENARIOS

The five scenarios to meet electricity needs in 2030 were compared to the current system in terms of capacity mix, energy mix, and gas and coal consumption. For each scenario, the capacity mix is shown in Figure 12, the energy mix in Figure 13, and the gas and coal consumption in Figure 14.

Figure 12
Capacity Mix Under Each Scenario
- GW -

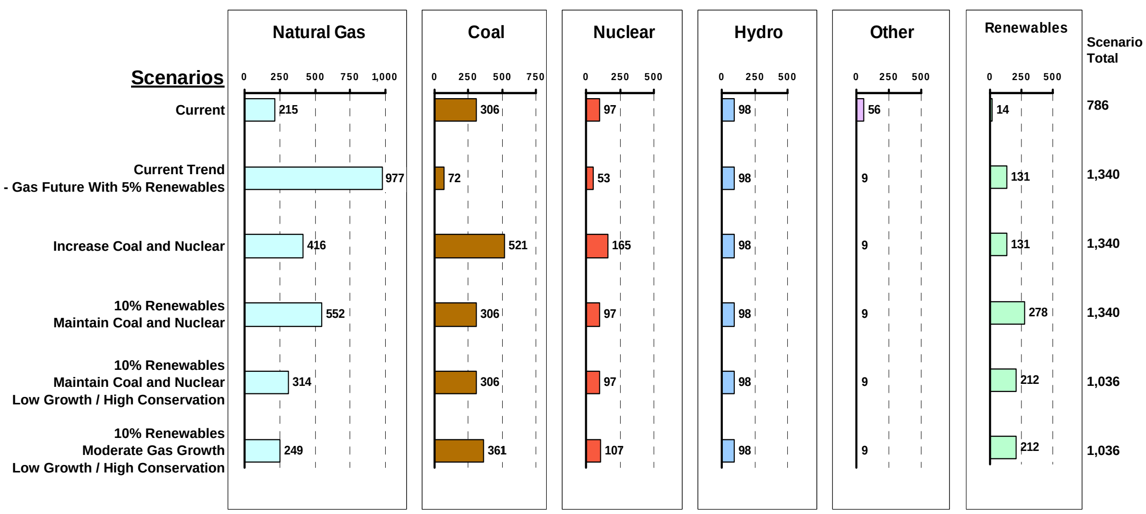

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Figure 13
Energy Mix Under Each Scenario
- billion kWh -

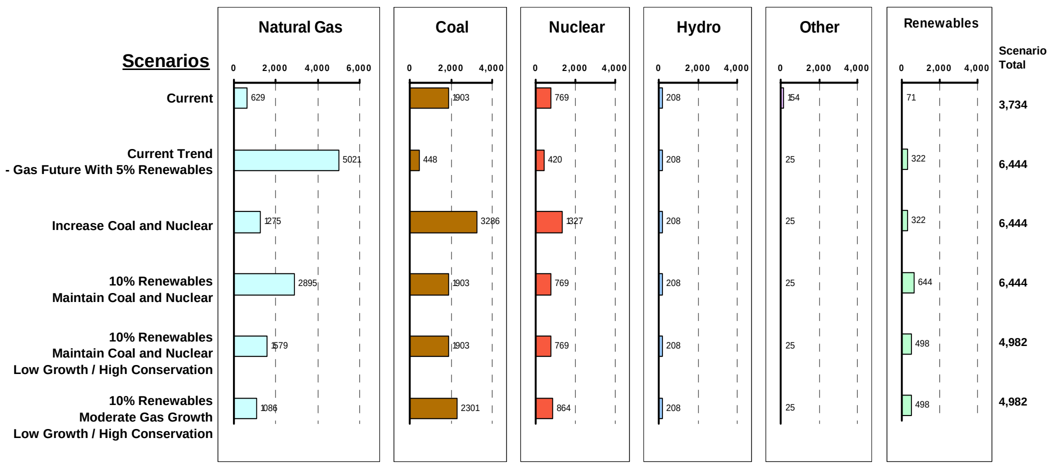

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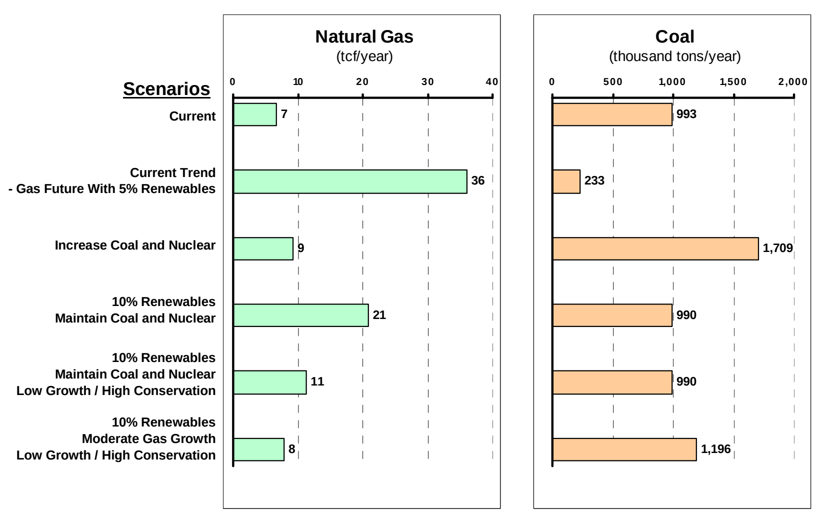
Figure 14
Fuel Consumption for Electricity Generation Under Different Scenarios



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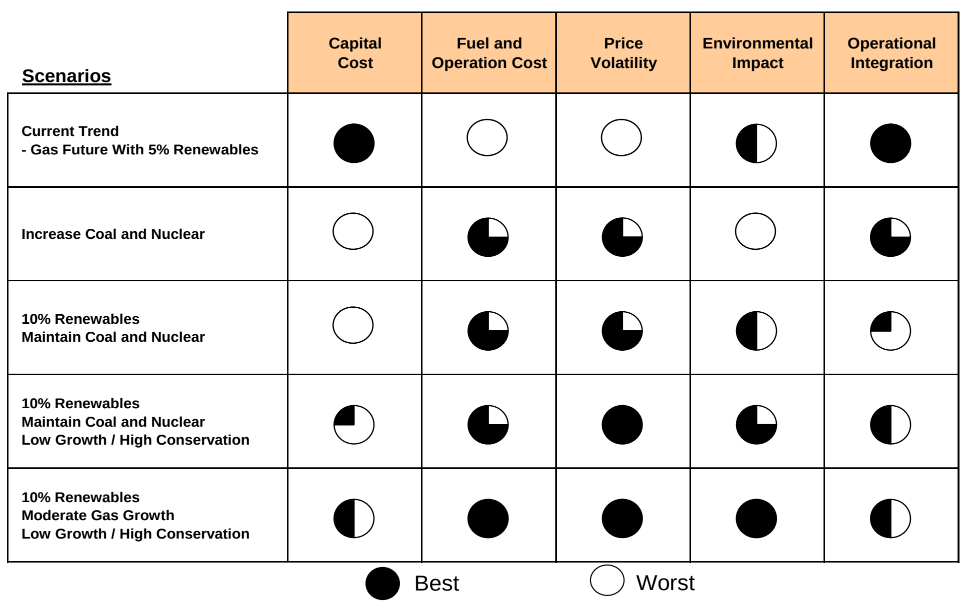
Under the current trend or *gas future with 5% renewables*, gas capacity and energy account for 70 to 80% of total requirements and gas consumption for electricity increases fivefold. This is clearly unsustainable. This gas dependence can be reduced by new coal and nuclear power plants as in the second scenario. However, a more balanced approach will be a mix of greater energy efficiency and conservation (lower load growth) high contribution from renewables, and some new coal and nuclear power plants to replace retiring plants and serve a portion of load growth. Clearly, foreclosing the coal and nuclear options is not a sustainable long-term policy.

Figure 15 provides a comparison of the scenarios in terms of key attributes such as capital cost, fuel and operation cost, price volatility, environmental impact and potential operational integration issues. This is meant to be illustrative of the relative impacts and a detailed assessment is required to fully understand impacts and implications.

Figure 15
Major Attributes Comparison for Different Scenarios



The first two scenarios are extreme, i.e., are best or worse in terms of attributes. Because of price volatility and high fuel and operation costs, the Current Trend -- Gas Future with 5% Renewables should not be preferred scenario. The gas requirements increase substantially and are not sustainable. The second scenario, i.e., Increase Coal and Nuclear, will have significant capital cost and negative environmental impact.

The other three scenarios are more balanced. Scenario five with 10% renewable, moderate gas growth and high conservation is the most balanced among these scenarios. Of course, lowering annual load growth to 1.0% and increasing capacity of renewable resources to 10% of the total may not be easily achieved. Also, due to intermittent nature of renewables, the actual capacity additions may be two to three times the firm capacity requirements, with associated high capital requirements and need to develop new capacity at many more locations, whether central or distributed.

IMPLICATIONS FOR TRANSMISSION AND RELIABILITY

In planning for the transmission interconnections for the future, the U.S. has to look ahead 25 to 30 years to allow adequate lead time for corridor planning, transmission rights-of-way, and coordination among states and utilities. Most of the existing transmission was planned 30 to 40 years ago. Major new transmission projects have ten year or longer lead-time. Generation projects are being planned on a much shorter lead-time. Hence, there is no reliable information on new power plant locations to guide long range transmission planning. Yet, if the long term transmission planning issues are not addressed, the opportunity to site needed new transmission interconnections may be lost or become prohibitively expensive, just as in the case of building new freeways or airports in population centers. Also, if transmission planning is reactive, there is a risk of stranded generation, increased congestion, and bottlenecks.

Transmission interconnections are needed to:

- Interconnect new generating power plants,
- Facilitate wholesale markets and regional power transfers,
- Assure deliverability of generation to meet customer loads,
- Eliminate bottlenecks and congestion,
- Limit generator market power, and
- Enable reliable electric system operation and prevent blackouts.

The current bulk power transmission system consists of 157,000 miles of 230 kV and above and connects 786 GW of generating power plants. Adding 700 GW to 1,000 GW of new power plants over the next 30 years will require interconnections, infrastructure upgrades, as well as new corridors for transmission lines. The circuit miles of new transmission lines will depend on several factors:

- Use of existing power plant sites for new power plants
- Local or remote siting of new power plants
- Ability to upgrade transmission capacity on existing rights-of-ways and corridors with new conductors and technologies (composites, superconductors, silicon and digital based control).
- Resource strategy.
- Type of transmission technology used for new transmission (e.g. AC or DC, composite conductors, superconductors).
- Voltage level for new transmission, e.g., 345 kV, 500 kV, 765 kV.

Depending on the scenario, new circuit miles of transmission could vary substantially. If new circuit miles of transmission are proportionate to current generation and transmission infrastructure, additional 140,000 to 200,000 miles will be required in the low growth and base case scenarios. However, newer technologies, better utilization of existing transmission infrastructure, and repowering or life extension of existing power plants can substantially reduce the amount of new transmission needed.

Transmission has a ten-year lead-time, which is substantially longer than many generation options. Consequently, it is critical to plan for future transmission corridors from resource rich regions or locations where power plants are likely to be sited. Transmission plans need to be linked with the assessment of resource availability, renewable, coal, LNG terminals, as well as resource strategies.

The location of new power plants is likely to have a significant impact on local reliability. For example, many of the existing power plants are located near load centers. As these are retired and replaced with remote generating power plants, one would need not only new transmission lines to connect the power plants to load centers but also invest in infrastructure to assure adequate local voltage supplies. However, if power plants are to be located near load centers either on an existing site or new site, then the implications for local reliability and construction of new transmission lines is substantially different. A qualitative assessment of implications for transmission and local reliability is presented in Figure 16. One thing is for sure, we have learned the transmission grid of the future must be dynamic, such that it will allow the deployment of generating resources throughout large regions, be able to self-adjust for contingencies and meet the local area ancillary service needs.

Figure 16
Assessment of Transmission Needs and Local Reliability

	Need for new Transmission Lines	Impact on Local Reliability
Full and Continued Use of Existing Sites	●	●
Develop New Sites Near Load Centers	◐	◐
Develop New Remote Sites	○	○
Distributed Genеartion and Lower Load Growth	◕	◕

● Least ○ Most

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SITING OF NEW POWER PLANTS

Currently, there are 13,500 power plants operating in the U.S. Many of these are small hydro power plants, which are expected to continue to operate. However, over 3,000 coal, nuclear, and gas fired power plants are expected to retire by 2030 as they would be 50 years or older. Building 700 to 1,000 GW of new power plants over the next 30 years is estimated to require new sites. The number of new sites will depend on the scenario and the degree to which existing sites can be utilized for life extension and repowering. An initial assessment of number of sites required is presented in Figure 17 and indicates that some where between 1,900-3,400 new power plant sites will be required. The location of these sites, i.e., remote or near load centers, and resource strategy will have significant implications for reliability management.

Figure 17
Number of Power Plants Required for New Generation

	Renewables (assuming 100MW/Plant) *	**Natural Gas** (assuming 750MW/Plant)	**Coal** (assuming 2,000MW/Plant)	**Nuclear** (assuming 2,000MW/Plant)	**Total New Sites**
`Current Trend - Gas Future With 5% Renewables	1,193	1,176	0	0	2,368
Increase Coal and Nuclear	1,193	428	225	56	1,901
10% Renewables Maintain Coal and Nuclear	2,664	609	117	22	3,412
10% Renewables Maintain Coal and Nuclear Low Growth / High Conservation	1,996	292	117	22	2,428
10% Renewables Moderate Gas Growth Low Growth / High Conservation	1,996	205	145	27	2,373

Note: A Power Plant can have one or more generating units.

***Firm capacity; nameplate capacity may be 2 to 3 times that of firm capacity due to intermittent nature of renewables.**

POLICY ISSUES AND INFRASTRUCTURE CHALLENGES

The U.S. electricity infrastructure is aging. In some ways, we are living off the planning and investment decisions that were made in the 60's and 70's. Well over 50% of the currently operating power plants may be retired by 2030. In recent years, public policy has favored renewables, gas, conservation, distributed generation, and load management. Investments in transmission have lagged load growth, population growth and power plant growth. Coal and nuclear options have been out of favor.

The U.S. has been moving to a competitive market structure, where the discipline of markets replaces regulatory mandates. Electricity has unique physical characteristics that make electric markets different than other markets. These include interconnected network, real time balancing of electricity supply and demand, no storage, and flow of electricity governed by laws of physics and not contracts. However, market and reliability issues are difficult to separate.

In the short time since the U.S. started the transition to competitive markets, there have been several events and trends that raise fundamental policy issues associated with meeting future electricity needs. Most notable among these are:

- California market dysfunction in 2000-2001.
- August 14, 2003 blackout that started in Ohio.
- Bankruptcy of Enron and collapse of power trading as major players have exited the business.
- Large debt burdens on major independent power companies resulting in weakened balance sheets and a near moratorium on new power plants without long-term contracts.
- Transmission investment shortfalls due to regulatory, market, financial, and business model uncertainties.

With this backdrop, without adequate infrastructure and given the unique characteristics of electricity, reliability suffers and this manifests itself in bottlenecks, low voltage, frequency swings, volatile prices, and inadequate reserves. For example, congestion and security management require physical actions to reduce loadings and change flows, which in a market system are handled through price signals. For markets to work there must be adequate generation and transmission assets to serve load and maintain reserves. Investments in grid solutions to expand and upgrade the network can eliminate bottlenecks and network constraints. However, there are significant institutional, regulatory and financial challenges and, hence, grid investments have been lagging. Figure 18 presents a summary of U.S. electricity infrastructure challenges.

Figure 18
U.S. Electricity Infrastructure Challenges -- Summary

- Inadequate electricity infrastructure manifests itself as bottlenecks, stranded generation, low voltage, frequency excursions, price volatility, and inadequate reserves to withstand contingencies.
- U.S. electricity infrastructure is aging and will have to be upgraded, rebuilt, replaced, and expanded to meet the needs for adequate, reliable, and reasonably priced electricity.
- New transmission construction has a ten year or longer lead time. Transmission has to be planned to accommodate regional power transfers, competitive markets, connect new generation, assure power deliverability and reliable grid operation.
- Investments are needed in new tools, technologies, controls and wide area monitoring systems to improve utilization of current infrastructure and plan for a smart grid.
- Local reliability and voltage management are likely to become more important with retirements of older generation located near load centers.
- U.S. needs a balanced strategy and cannot rely exclusively on gas fueled power plants to meet future needs for 700 to 1,000 GW of new power plants..
- Contribution of price responsive demand distributed generation and new renewables needs to be expanded for market efficiency, reliability, environmental and price stability goals.
- Continued use of existing and development of new coal and nuclear are important building blocks of U.S. future electricity infrastructure.
- Reliability management needs to transition from local to wide area or interconnection management with mandatory standards. Investments are needed to add required intelligence, monitoring tools, controls and other technologies for managing reliability and regional markets.
- New technologies – composite and superconductors, storage, power electronics, distributed controls, dynamic measurements, wide area monitoring, and demand management all need to be developed, demonstrated and integrated with the electric grid.

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SUMMARY

Alternative scenarios of load growth and mix of power plants to meet future electricity needs in 2030 provide a context for the policy issues and challenges for the U.S. electric power industry. These scenarios show a need for 700 to 1,000 GW of power plants over the next 30 years to replace retiring power plants and meet demand growth, virtually duplicating the entire electrical infrastructure that has been built in the last 100 years. The U.S. energy policy has to grapple with many long-term policy questions:

- Where will these power plants be built?
- What mix of power plants – renewables, gas, coal, nuclear – will be built?
- What steps are needed to promote investments in renewables, demand management, conservation, and distributed generation?
- What steps have to be taken to build needed transmission, pipelines, and other electric infrastructure?
- Who will finance and build these needed facilities?
- What mechanisms will guide electricity policy – markets, utility planning, state regulators, federal policy mandates?

These are significant electricity infrastructure challenges that need to be addressed. The current grid has to be transformed into a smart network with investments in new technologies, and new infrastructure has to be added for load growth and to replace aging infrastructure.

Major issues facing the U.S. electric power industry are:

- Investments for power plants and transmission infrastructure for reliability and market efficiency.
- Market and regulatory mechanisms to foster a diversified and balanced resource portfolio including renewables, energy efficiency, distributed generation, demand management, nuclear and coal rather than exclusive reliance on gas-fired power plants.
- Investments in new technologies to create a smart grid.
- Addressing reliability and operating challenges of large-scale inter-regional power transfers and competitive regional markets.
- Siting of energy facilities to replace aging infrastructure and meet needs of a growing economy, including siting of power plants, transmission lines, LNG terminals and pipelines.

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