Electric System in Crisis

More Power Plants or a Lower-Cost, Greener Solution?

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by

William Ryan, Ph.D.

Research Associate Professor

Department of Mechanical Engineering

University of Illinois at Chicago

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William Ryan, Ph.D., Research Associate Professor, Department of Mechanical Engineering, University of Illinois at Chicago

Consistent, reliable electric power is generally taken for granted by the modern consumer. Flip a switch or press a button and lights, computers, office equipment, household appliances and a myriad of other electrically driven devices come to life, making today's workdays and lifestyles more productive, convenient and enjoyable.

However, the system we depend on to satisfy our enormous appetite for electric power is aging, overloaded and at risk for breakdowns, brownouts and blackouts. Possible solutions include constructing new power plants and expanding transmission systems. Some think these are the only viable solutions. Yet the cost of these options is likely to significantly raise electric rates.

Considering the potential expense, a look at what drives the need for more capacity and the opportunities that exist to do more with the current system is important.

DEMAND FOR ELECTRICITY EXCEEDING SUPPLY

In reality, electricity is simply one form of energy. Perceptually, it is a valuable commodity, a business resource, a 24-hour-a-day and seven-day-a-week expectation, and an essential convenience—always available and plentiful. With deregulation in the electric market, it is becoming apparent that to meet customer demand the infrastructure component—that is, the generation, transmission and distribution equipment—constitutes the greatest portion of the overall price of electricity.[1] Infrastructure costs can make up 60% to 70% of total electric price as illustrated in Chart 1. Additionally, the more erratic the load, the more infrastructure needed to deliver the same amount of energy.

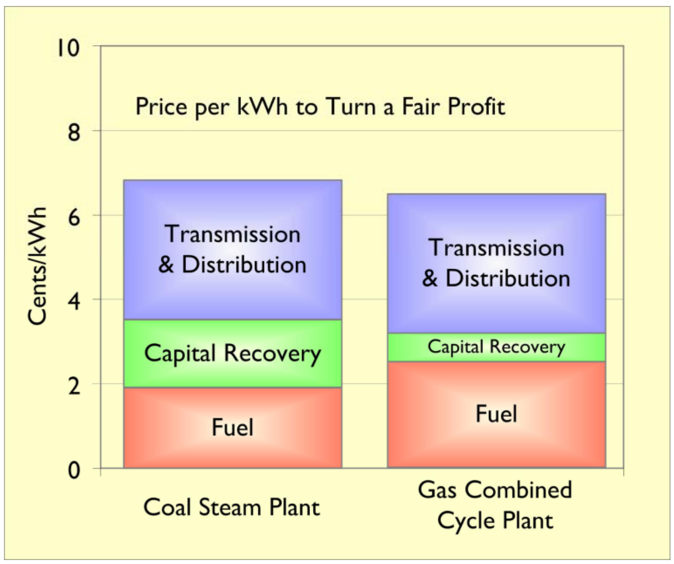


Chart 1: Cost of Generating Electricity
Although difficult to calculate fully, estimating the costs of generating electricity from a new generating station and delivering that electricity can be instructive. Best current estimates show total cost including a reasonable profit to be higher than electric prices in many areas, indicating that older infrastructure is being heavily depended upon.

Traditionally, industrial customers with their large and steady loads covered a major portion of infrastructure costs under regulated "rate base" schedules. As the electric market deregulates, the rate base structure that once spread infrastructure costs over all classes of customer can no longer effectively shield customers with less consistent loads, such as commercial buildings, from the brunt of these costs. Manufacturers can now leverage their large, steady loads on the open market to secure more attractive (i.e., less expensive) power arrangements. With manufacturing customers "buying out" to private electricity providers, commercial and residential rates must rise to cover the cost of the infrastructure these customers actually use.

This shift is occurring at a time when the existing infrastructure is significantly antiquated and overloaded. George Gross, a leading electric system expert, noted, "The need to strengthen the existing transmission infrastructure, to expand it and to effectively harness advances in technology constitutes the single most pressing challenge for the country's electricity system."[2] Transmission overload was identified as the cause of the East Coast Blackout in 2003[3].

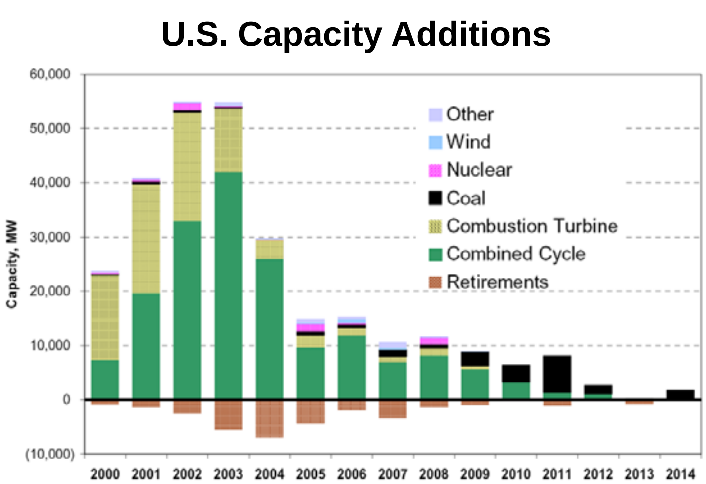


Chart 2: Slower Generation Construction
Mistrust of the capital markets following the Enron collapse, controversy over new large coal plants due to global warming, and slower gas plant construction due to higher gas prices combined to reduce power plant construction.

Despite strains on the existing system, additional generating capacity has and is projected to continue to decrease as indicated in Chart 2.[4] Given the significant impact of infrastructure costs on electric prices, a better approach may be to limit peak electric demand rather than focus entirely on efficiency measures that may have no impact on demand.

EFFORTS TO MEET DEMAND CONSTRAINED

Some problems plague the electric transmission system in specific areas, especially the crowded urban Northeast and California.[5] Major issues concern the cost of land to expand the network, public objections to new power lines, and the lack of a clear line of responsibility for the soundness of the transmission network in a deregulated environment. Under deregulation, the transmission network can be compared to an interstate highway for electric power. Like a toll road, regional authorities collect the tolls and should be responsible for maintenance of the system. These lines of responsibility are only just beginning to emerge, and, as they do, little upgrading of the transmission system is taking place. Additionally, it is unclear if the transmission charges currently in place will sufficiently pay for the required work.

OPEN MARKET ELECTRIC PRICE INSTABILITY

Another shift in the marketplace as a result of deregulation is occurring in the ownership of the plants that generate power. Regulated utilities once generated most or all U.S. electricity. In today's deregulated environment, regulated utilities purchase power on the open market from privately owned generators. In this open market venue, the principles of supply and demand dictate electric pricing. Price increases are passed on to the end-use customer.

As a result, a very real image of the value of electricity on an hour-by-hour basis begins to emerge, especially during the critical peak summer period. Given generation and transmission constraints, the price of electricity on hot summer days tends to spike. For example, Chart 3 (next page) illustrates hour-by-hour price fluctuations on a day where peak electric prices climbed from \$0.04/kWh to \$0.60/kWh on the PJM Interconnection* trading system. This type of price instability is becoming a trademark of an overloaded summer electric market.

CONCURRENT LOADS AND THE COOLING LOAD

A closer look at the components of demand shows that all electric loads do not contribute equally to peak demand. Many load types tend to be non-concurrent. That is, they occur at different times of the day or week and, therefore, contribute less to regional peak electric demand. For example, the power to light large office buildings diminishes at the end of the workday simultaneous with an increased need to power residential indoor lighting and retail signage. Averaging over thousands of loads and load types reveals significant dispersion over the day or week.

However one load stands out as highly coincident … the air conditioning or space cooling load. Met almost entirely by electric equipment, this load waxes and wanes with outdoor temperature and humidity levels and affects all structures in a region simultaneously. In other words, air conditioning loads peak together. Thus, peak demand, higher electric wholesale prices, and electric supply problems tend to correspond to hot weather. This is evidenced by the fact that annual peak demand for 49 of the 50 states and Canada occurs in the summer. It also explains why statistics on the adequacy of the generation and transmission system all focus on meeting summer load.

The North American Electric Reliability Corporation's (NERC)[6] **2007 Summer Assessment: The Reliability of the Bulk Power System in North America** begins with the following warning based on the 2006 season:

> Extreme weather was experienced across much of North America in the summer of 2006. Record peak demands depleted available resources, which necessitated the implementation of preplanned emergency procedures in some areas to maintain a balance between supply and demand.[7]

NERC cites the following hot weather circumstances as contributing to a "perfect storm" condition for the electric transmission system.

1. High demand is driven by cooling loads.
2. Gas turbine peaking plants are de-rated at high air temperatures.
3. Substation failures increase at high temperatures.
4. Run-of-river hydro and wind generation capacity declines in hot weather.

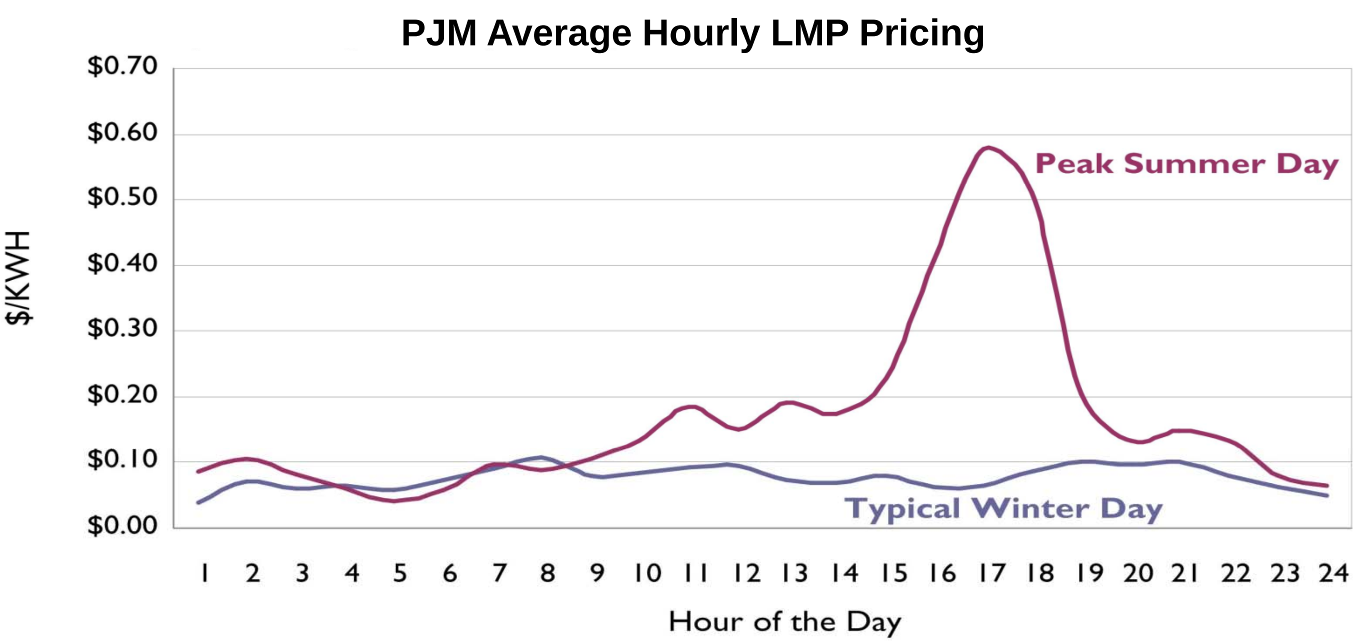


Chart 3: *On a hot summer day, prices fluctuate hourly and tend to spike, as shown in the illustration where prices climbed from $0.04/kWh to $0.60/kWh.*

** PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and District of Columbia.*

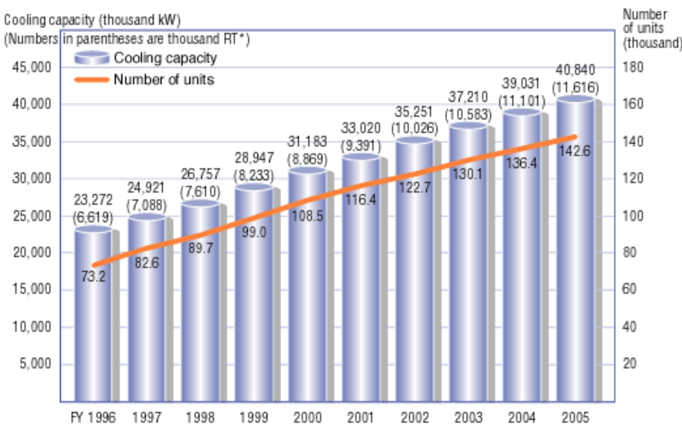
It is well known that the infrastructure investment needed to meet cooling loads is an expensive problem. In Japan, non-electric chillers are required in larger commercial buildings, resulting in a sizable market for gas cooling (see Chart 4). Government policies in China and South Korea also encourage the use of non-electric equipment. These countries implemented such policies to help minimize heavy government-subsidized investment in electric generation and delivery.

In contrast, under regulation the American electric industry rolled the cost of excessive infrastructure into the rate base. The allowable rate of return was calculated as an annual percentage of the rate base, meaning that a larger rate base allowed greater returns. Thus far under deregulation, the industry has taken the opposite approach of minimizing investment to maximize an unregulated rate of return. In such an environment, new non-electric cooling technologies should move to the forefront as a means of reducing demand on an overstressed infrastructure. However, the American building design community remains entrenched in a long tradition of electric cooling.

The Japanese Market

Sales of Gas Cooling in Japan: 1996 to 2006

(Values are in 1,000's of kW and Tons of Cooling)



Annual Japanese Gas Sales by Month

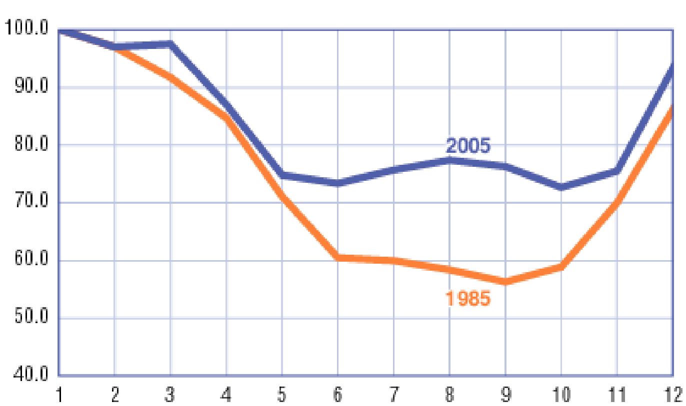


Chart 4: *Japan controls their investment in electric generating capacity and transmission through policies that reward the use of gas cooling. Summer use of gas in commercial buildings increased to nearly 80% by 2005. Systems shown are large chillers. Small air conditioners are generally electric.*

EXPLORING ALTERNATIVE COOLING OPTIONS

Capital Costs

Reducing demand at the source through aggressive use of alternative cooling options is less expensive overall than utility peaking turbines as demonstrated in Chart 5. This chart compares various cooling technologies for meeting the needs of a large commercial building, using a conventional electric chiller (line 1) as the base case. The Total Demand (column 2) represents the daytime electric demand added by each technology. The Cost of Demand Reduction (column 3) was calculated by first completing a first-cost assessment for each type of cooling system, then dividing the added cost, above that of a conventional electric chiller, by the amount

Plant Type	Total On-Peak Demand	Cost of Demand Reduction
	kW	$/kW
All Electric	780	NA
High Efficiency Electric	700	$625
DFDE Absorber	300	$469
Engine Chiller	250	$538
Full Ice Storage	100	$662
Onsite Generation	0	>$600
Utility Peaking Turbine	0	>$1000

Chart 5: Cost of Meeting Electric Demand

Reducing demand at the source through the aggressive use of alternative cooling options such as natural gas absorption and engine-driven chillers is less expensive overall than utility peaking turbines. Values are for a 1,000 ton cooling plant and include all tower and cooling water pumps.

of demand reduced. The Cost of Demand Reduction is shown on a dollar per kW of demand reduction basis.

For example, opting for a high-efficiency electric chiller rather than a conventional electric chiller reduces demand from 780 kW to 700 kW. The additional first cost of this option amounts to $625 for each kW of avoided demand. An ice storage system requires no additional daytime demand, but the cost of the ice storage system adds $600 for every kW of demand reduced.

Although the cost of simply adding an on-site generator to carry the chiller plant varies, it is still more than $500/kW. For smaller facilities requiring generators of less than 500 kW, this cost can be $1000/kW or more.

At $1,000/kW, the cost of the electric utility carrying the demand, using the least expensive solution of peaking turbines and the needed transmission and distribution to deliver the peak electricity, is the most expensive option. Even so, many experts consider this estimate to be conservatively low.

At $469/kW and $538/kW respectively, the gas cooling options, absorption and engine chillers, offer the lowest-cost demand reduction.

If gas absorption and engine chillers are the least expensive approach to demand reduction, why aren't more natural gas systems specified for commercial buildings? The reason is a market defect that penalizes commercial building owners who choose natural gas. The costs shown in Chart 5 are overall. If gas cooling is specified, the first cost falls entirely to the building owner. When electric cooling is installed, the first cost of the needed electric capacity has traditionally been spread across all electric consumers as part of the rate base. This inherent subsidy by non-commercial ratepayers allows commercial building owners to avoid rate structures that encourage the use of less expensive alternative cooling options. As industrial customers abandon regulated rates in many states, the only remaining major customer class, the residential consumer, will increasingly pay this subsidy.

Demand Reduction Potential

When estimating the potential for demand reduction, it must be recognized that the opportunity in commercial buildings occurs when an existing chiller is replaced or during new construction. Each year, manufacturers produce large chillers, or cooling systems targeted to new and existing large commercial buildings, equal to approximately 3,000,000 refrigeration tons. If natural gas technologies displace electric chillers in half of these installations, demand shrinks by 900 MW per year, thereby eliminating the need to build one large coal or nuclear plant per year. Based on the NERC's North American demand growth projection of 15,000 MW/year over the next 10 years[8], the policy of promoting non-electric equipment makes sense.

More importantly, the largest markets for gas cooling in commercial buildings, which predominate in the metropolitan areas, are the most capacity constrained. Demand reduction in cities along the Eastern Seaboard, the West Coast, and portions of Canada can alleviate their most critical challenge, the inability to import sufficient power regardless of the source.

2004 Total Generation	2004 SO2 Emissions	2004 NOx Emissions	2004 CO2 Emissions	2004 Hg Emissions
(MWh)	(pounds/MWh)	(pounds/MWh)	(pounds/MWh)	(pounds/MWh)
3,945,431,404	5.22	1.98	1284.66[9]	0.000024

Chart 6: Emissions from Power Plants in 2004[10]
These values are national averages for each MWh of electricity produced from whatever source including those that do not emit these pollutants such as wind, nuclear and hydro power. As such, this represents the environmental footprint of every MWh produced given the current national mix of power plants. Canadian values tend to be lower due to the larger percentage of hydroelectric power used in Canada.

Many of these areas are dealing with localized negative summer reserve margins, requiring enactment of emergency demand reduction programs for every hot weather period. Currently the most constrained areas are New York, New England, Ontario, Southern California, and Texas. All have total summer reserve margins below 15%. Specific areas like Southern Connecticut and Boston have negative summer reserve margins for all power whether internally generated or imported.

Gas Cooling and Emissions

Given the current national mix of power plants, Chart 6 (previous page) shows the national average emissions for each MWh of electricity produced.

The impact on emissions when using gas cooling technologies rather than electric chiller equipment depends on the source of the electric power. For electric chillers running on typical power supplied by the grid, CO_2 emissions are lower for the gas engine-driven chillers than the electric units (see Chart 7). However, the chillers will operate during periods of peak summer demand when electricity generators must rely on peaking gas turbines to produce marginal power to cover peak loads. Since the gas cooling option can supplant peaking turbine operation, the gas engine and peaking turbine present a more valid comparison of CO_2 emissions.

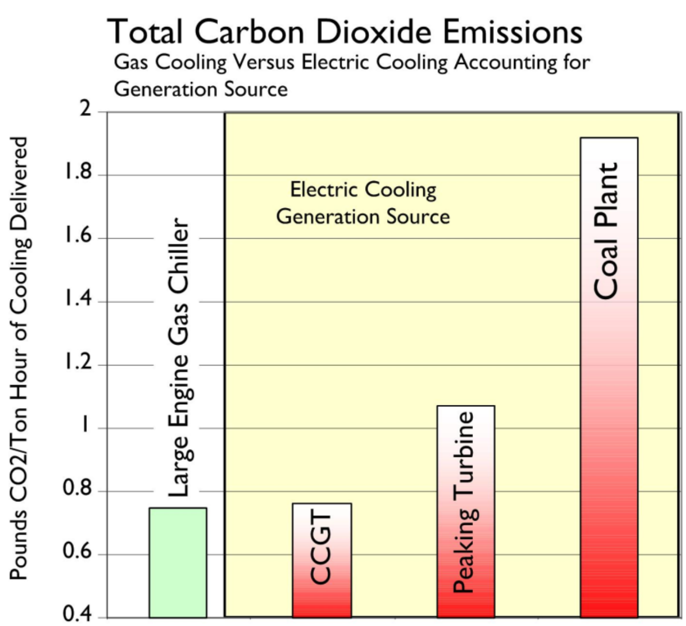


Chart 7: Cooling and Global Warming
Carbon dioxide emissions due to gas or electric chiller operation. Electric chiller values vary depending on the generation source.

A comparison of sulfur dioxide emissions for electric and gas technologies is much simpler. Every 1,000-ton hours of cooling from an electric chiller, running on typical grid power, will release 3.1 pounds of SO_2 into the atmosphere. Conversely, sulfur compounds are removed from pipeline quality natural gas. Therefore, gas cooling (and cooling run by gas peaking turbines) will produce effectively zero sulfur dioxide. Similarly, mercury emissions are no problem for systems operating on natural gas, as natural gas contains no mercury.

GAS COOLING AND WATER USAGE

Water is a critical resource in many parts of North America and is used both during power generation and by cooling systems. Power generation uses water to reject energy that cannot be converted to electricity by evaporating water in cooling towers. Cooling chillers reject heat in the same way.

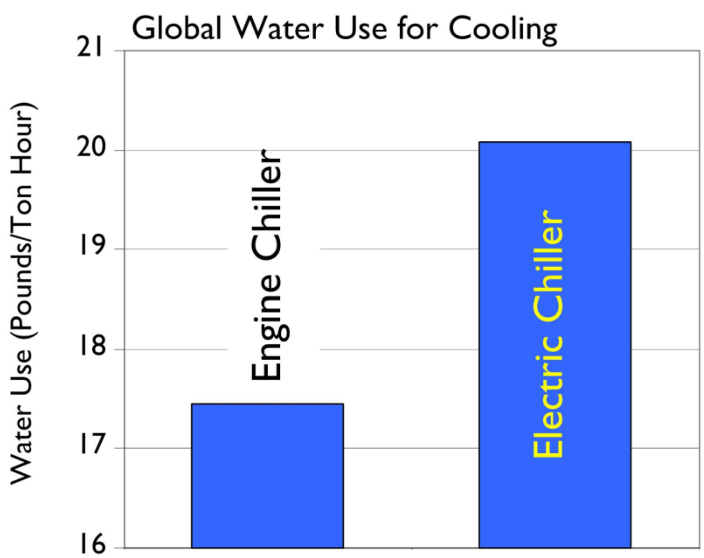


Chart 8: Water Usage for Large Cooling Systems
Water usage for the electric cooling system includes water used at a typical fossil fuel power plant.

Although electric chillers reject less heat than gas engine or absorption chillers, a valid comparison takes into account the water used during the electric generation process to determine the water usage of the electric chiller. As shown in Chart 8, natural gas engine chillers use less water overall.

SMALLER GAS COOLING SYSTEMS

A larger potential market exists for gas cooling in smaller equipment. Smaller air conditioning systems are sold at a rate of approximately 8-10,000,000 tons per year in North America. However, at present there are few producers of gas cooling systems in these smaller residential or light commercial sizes. Given the societal benefits possible, development efforts into practical systems for this market seem warranted. Advantages in this area of the market include:

- The market for smaller cooling units represents an even greater potential for demand reduction.
- Small-sized gas units, serving residential and light commercial loads, can reduce power demand on both the transmission and the extensive low voltage distribution systems, yielding even greater infrastructure savings.
- Some of these units can also be fired on propane or oil, allowing for load relief on lengthy and expensive-to-maintain rural electric distribution systems.
- Small-sized gas air conditioning equipment is air cooled and requires no cooling water. Since the equipment is gas fired, the units do not contribute to water usage at power plants and use no water on site, making the overall water consumption effectively zero.

Gas-fired heat pump

- Small gas air conditioning systems are generally set up to operate as heat pumps in the winter, providing a greater level of efficiency than any existing gas heating system. Gas heat pumps can also provide space heating at a lower carbon emission rate than any other form of space heating (see Chart 9).

Gas Heat Pumps and Carbon Emissions

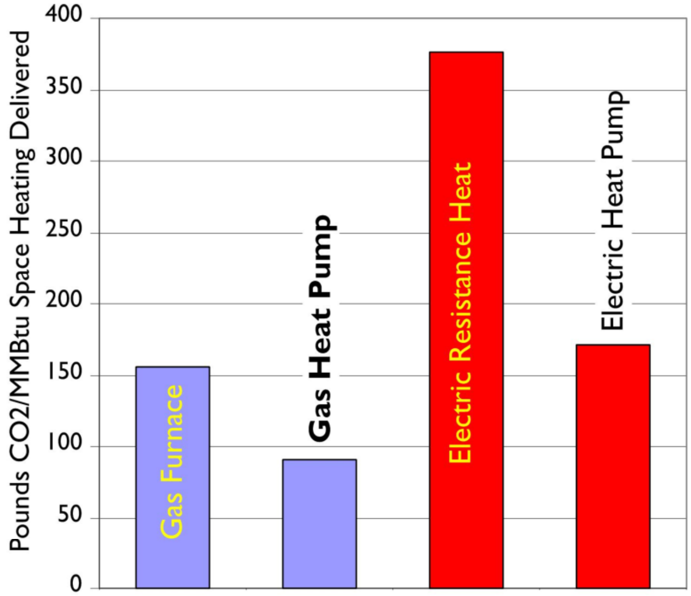


Chart 9: *No other available form of heating is as low in carbon dioxide emissions as a gas heat pump.*

THE GAS SYSTEM

This discussion focused on the maximum summer loads experienced by the electric distribution system and the transfer of some cooling load to the gas distribution system. As shown in Chart 10, (next page) the gas distribution system is very lightly loaded in summer months. Even with the greater use of gas for power generation, long distance transmission capacity significantly exceeds summer sales. In addition, urban gas distribution systems, sized for the heating season, are very lightly loaded in the summer. Moving a significant portion of the cooling load from the electric to the gas distribution system effectively aids in leveling the loads on both systems, maximizing usage of the current investment in both distribution systems. Given that distribution costs remain regulated and are ultimately paid for by the energy ratepayer, making the best use of this investment is in the public interest.

Gas & Electric Demand

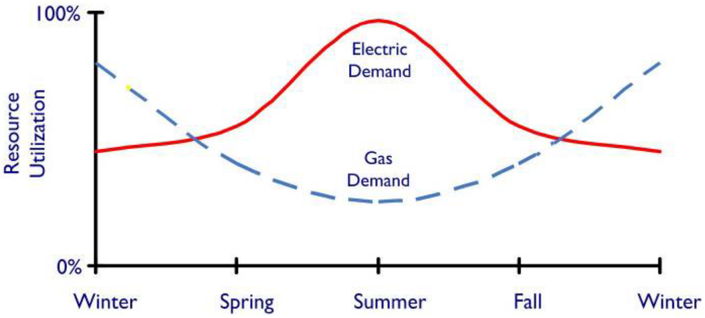


Chart 10: General Pattern in Gas and Electric Demand
Electric systems peak in the summer and gas systems peak in the winter. Growth in gas usage for electric generation has not significantly changed this traditional pattern.

SUMMARY

The opportunity to control and minimize the investment needed in the electric infrastructure to meet growing demand through the use of gas cooling technologies is substantial. Implementing the following actions will prime the marketplace for wider acceptance of natural gas cooling as an economically and environmentally viable alternative.

- Eliminate the current "inherent subsidies" promoting electric cooling through the application of electric rates that do not spread the cost of this subsidy to residential rate payers.

- Educate designers of commercial buildings about the advantages of gas cooling.

- Develop a domestic market for the smaller gas cooling systems that have successfully proven their value in overseas markets.

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[6] NERC, The North American Electric Reliability Council (now Corporation), is responsible for reviewing the adequacy of the North American electric infrastructure. Each year they prepare a summer assessment based entirely on this concern.
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[9] This amounts to 1,284 lb/kWh in reasonable agreement with the 1,340 lb/kWh found from the 2002 data.
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