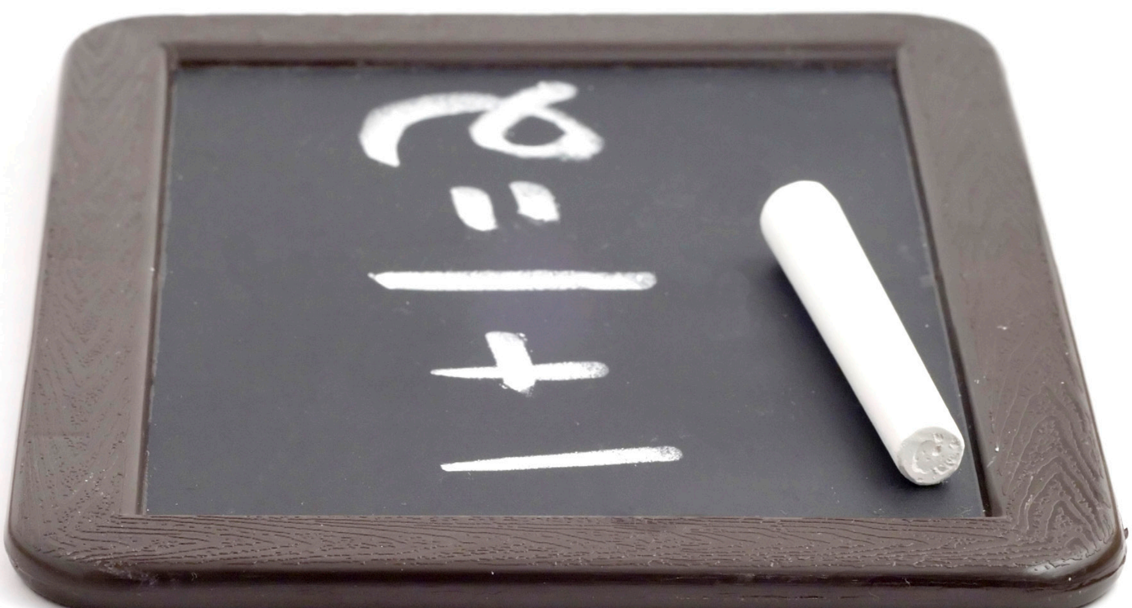
Deloitte.

The math does not lie.

Factoring the future of the U.S. electric power industry



Deloitte Center for Energy Solutions

Contents

Introduction

What will the U.S. electric power industry look like in the future? This question has been asked numerous times with many different answers, and current industry trends make it an especially relevant question today. Discussions with senior electric power company executives suggest a lot has changed over the last four years that is challenging the conventional wisdom about where the industry may be heading. Recent Deloitte research supports these executives' views, and highlights important emerging trends which suggest power and utility companies reassess their business strategies and explore new business models.

This paper examines what has changed in the electric industry and provides industry stakeholders with a straightforward approach to examining the future through a simple framework using a mathematical equation.

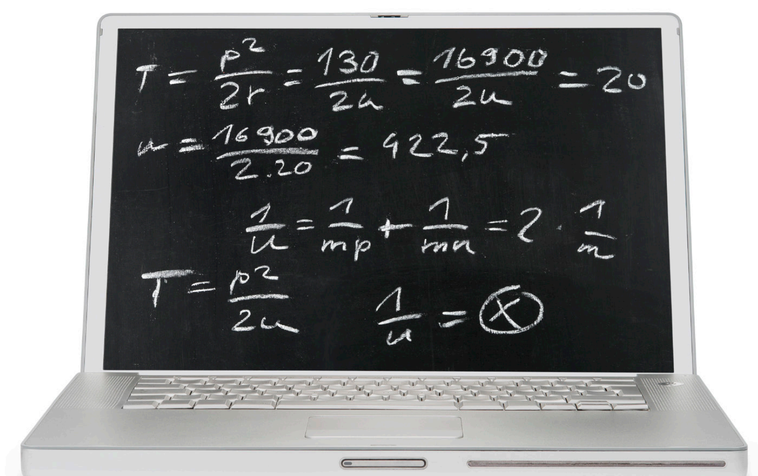
The "math" is dictated by two emerging trends, which, in combination could present a formidable challenge to the profitability of companies in the electric industry. The two future trends are steeply rising costs coupled with the potential for slow, stagnant, or even declining electricity consumption. Together, they may well alter the equation for the power sector during this decade.

The first trend, rising utility costs, stems from an unprecedented increase in capital spending to address aging infrastructure, an evolving set of environmental regulations, renewable portfolio standards, nuclear plant safety mandates, and changes in the cost of capital, among other factors. The second trend is stable or declining levels of electricity consumption, as projected by government and industry analysts. The Energy Information Administration's (EIA) Annual Energy Outlook 2012 projects that net electricity available to the grid will increase from 3,938 billion kilowatt hours in 2012 to 4,084 in 2020.[i] These numbers reflect the assumption of growth in electricity consumption at an annual level of just 0.73%.[ii]

Other projections present an even gloomier picture. A November 2011 Brattle Group report, "Energy Efficiency and Demand Response in 2020" predicts that factors such as increased energy efficiency, new smart grid technologies and structural changes in the economy will cause electricity demand and consumption in 2020 to decline 7.5 to 15 percent and 5 to 15 percent, respectively, as compared to what they would have been without efficiencies.[iii]

Deloitte's 2011 and 2012 reSources Studies reveal emerging trends in the attitudes and behavior of electricity customers, both residential consumers and businesses, and support this outlook for moderating electricity consumption.

Assessing the impact of these trends can make planning for the future a daunting task for even the most seasoned utility executives. This paper advances a straightforward approach which can serve as a common framework for addressing the state of the industry between now and 2020. The reasons for selecting this timeframe are outlined on the following page.



[i] U.S. EIA Annual Energy Outlook 2012 Table "Electricity Supply, Disposition, Prices, and Emissions Reference case" http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=6-AEO2012&table=8-AEO2012&region=0-0&cases=ref2012-d020112c

[ii] Ibid

[iii] Energy Efficiency and Demand Response in 2020, Ahmad Faruqui and Doug Mitarotonda, The Brattle Group, Inc. November 2011

Planning for the near term

The period from today to 2020 may seem like a long time, but it is less than eight years. To put eight years in perspective, consider the following:

- It takes, on average, approximately 2 to 3 years to construct and commence operations of a 500 to 700 megawatt state-of-the-art combined-cycle natural gas-fired plant (excluding permitting).[iv]
- Among the most recently completed coal-fired plants, Longview Power's 695 MW (net) supercritical pulverized coal-fired power plant in Maidsville, WV, took five years to come online after obtaining final permits in January 2007.[v]
- The current scheduled completion dates of Georgia Power's Vogtle nuclear plant and SCANA's V.C. Summer nuclear station are 2016 and 2017 respectively – following a process that will have taken 9 to 10 years from the dates applications were submitted to the Nuclear Regulatory Commission (NRC).[vi]
- One of the most recently completed transmission lines, San Diego Gas & Electric's Sunrise Powerlink, took six and a half years from the utility's initial filing in December 2005 with the California Public Utilities Commission to its completion in July 2012.[vii]

Eight years is not far away. And, even in this short time frame, the future of the U.S. electric power industry is an extremely complex question impacted by many known and unknown factors including:

- The global and U.S. economy over the next eight years
- Coal, natural gas and nuclear fuel prices
- Federal and state policy and regulation
- Technological advances
- Changing customer behaviors and demands

Despite this uncertainty, if the various interested constituents can agree in principle on a framework, then projecting the state of the industry can start with a more focused analysis of the significant factors that may impact that framework. Taking the concept further, if the fundamental framework is a mathematical equation, interested parties can focus on the variables in the equation, and attempt to reach common ground on:

- The sensitivity of the answer to the equation of the various variables
- The sensitivity of the variables to each other
- And, a point of view on the value, or amount, of the variables both now and in the future

To put it simply, the math does not lie.

[iv] Based on timelines for projects in the advanced development stages. Source: SNL database

[v] Federal Energy Regulatory Commission, *Office of Energy Projects Energy Infrastructure Update*, January 2012

[vi] U.S. Nuclear Regulatory Commission

[vii] *SDG&E dedicates Sunrise Powerlink transmission line, PennEnergy*, July 26, 2012 <http://www.pennenergy.com/index/power/display/4211213931/articles/electric-light-power/t-and_d/transmission/2012/July/SDG_E_dedicates_Sunrise_Powerlink_transmission_line.html>

The math

The key is to keep the math simple and straightforward, because as soon as complexity creeps in, the ability to reach common ground, or consensus view, is likely lost. The math in its simplest form is the following equation:

Cost of electricity sold ÷ Number of kilowatt hours (kWh) consumed = Cost per kWh sold

This simple equation is easy to understand and hard to debate. The answer to the equation is for cost per kWh sold, not necessarily the price charged to the customers.[viii]

A slightly expanded version of the equation is as follows:

Cost of electricity sold

- **Capital costs**
  - – Depreciation
  - – Interest expense
  - – Shareholder return
- **Operations costs**
  - – Fuel
  - – Operations and maintenance
  - – Taxes

Divided by

kWh consumed

= Cost per kWh sold

The slightly expanded equation is also straightforward. The cost of electricity (or the numerator) is comprised of capital costs (including some amount of income or return to shareholders/owners) and operations costs.

Influencing the variables

The next step is to identify those factors which can significantly influence the three variables in the equation – capital costs, operations costs and kWh consumed. This is where the temptation to overanalyze should be avoided. A high degree of sophistication and accuracy are likely not warranted, and can quickly take the discussion to a level of minutia that defeats the objectives of the exercise.

The factors identified below are proposed as being those most likely to impact the variables in the equation. That is, those factors most commonly identified as significantly impacting capital costs, operations costs, and kWh consumed in the reasonably foreseeable future (between now and 2020).

Capital Costs:

1. New investment in generation, transmission and distribution assets
2. New investment to achieve environmental regulation compliance
3. New investment to meet renewable portfolio standards
4. New investment to comply with nuclear safety regulations
5. Changes in cost of capital/interest rates

Operations Costs:

6. Changes in the cost of fuel
7. Incremental operations costs of environmental compliance retrofits
8. Introduction of new technologies

kWh Consumed:

9. Changes in weather
10. Changes in the economy
11. New sources of electricity demand
12. Technological advances in energy efficiency
13. Customer attitudes and behaviors

What can be generally agreed upon, and reasonably measured today, as it relates to these 13 factors? The discussion that follows is not an attempt to quantify the variables, but instead to demonstrate their potential magnitude over the next eight years.

[viii] The author recognizes that electricity tariffs include a fixed demand charge and an energy charge based on consumption in terms of kilowatt hours (kWh). In all but a few electric utilities (where the regulators have adopted full "decoupling" or a straight fixed-variable rate design), the dominant revenue recovery mechanism for electric utilities is the kWh charge. Thus, in the spirit of keeping it simple and straightforward this paper addresses the cost of electricity on a kilowatt hour basis rather than dividing the cost between demand and energy components.

The numerator – capital costs

New generating plant investment – The utility industry is expected to invest over $150 billion in new generation capacity from 2012 to 2020.[ix] Substantial investment in new generating plants is expected regardless of the level of future demand for electricity and the future price of natural gas. This is necessitated by an aging fleet and early retirements of uneconomic plants often due to the costs of environmental compliance.

New transmission investment – Based on estimates by the Brattle Group, the industry will invest approximately $100 to $120 billion in new transmission assets from 2012 to 2020.[x] Significant investment in transmission assets is being driven to maintain grid reliability and to integrate new renewable energy sources often associated with renewable portfolio standards.

An IHS Emerging Energy Research study (IHS) indicated that total transmission investment for the period from 2011 to 2020 will be approximately $102.5 billion. This number is derived from the study's prediction that investment in high voltage transmission (greater than 345 kilovolts) in the U.S. will exceed $41 billion during the period, and that high voltage transmission accounts for about 40 percent of total U.S. transmission investment.[xi] IHS also projects that more than 40 percent of this high voltage transmission investment will be made by 2014.

New distribution investment – New distribution asset investments will be substantial, not only to meet ever- changing residential, commercial and industrial infrastructure requirements but also as a result of smart meter investments by the majority of the electric distribution sector. Smart meter deployments from mid-2012 through the end of 2015 alone could cost approximately $4.4 to $11.6 billion.[xii]

The Institute for Electric Efficiency (IEE) found that 36 million smart meters had been installed as of May 2012 and estimated that 65 million will be deployed by 2015.[xiii] This represents approximately 675,000 smart meters installed per month between mid-2012 and the end of 2015. IDC Energy Insights predicts that by 2014 demand response will replace smart meters/AMI as the utilities' "most active smart grid investment area."[xiv]

Environmental compliance – Capital expenditures for existing power plant retrofits will continue. And, the future expenditures are expected to increase largely as the result of Environmental Protection Agency (EPA) regulations – namely the Mercury and Air Toxics Standards (MATS) rule, which is scheduled to go into effect in 2015. EPA estimates the incremental compliance cost of MATS to be approximately $9.4 billion annually in 2015, declining to $8.6 billion in 2020 and $7.4 billion in 2030. These estimates suggest a total incremental compliance cost of nearly $55 billion for the six years from 2015 through 2020.[xv]

The Cross State Air Pollution Rule (CSAPR), which was vacated by the U.S. Court of Appeals for the District of Columbia Circuit in August 2012, would have cost another $2.4 billion annually, and since some of this investment was assumed in EPA's MATS analysis, MATS-related costs may be somewhat higher now that CSAPR is not a factor. Even if the MATS rule were also struck down, other proposed EPA rules will require substantial investment. For example, EPA's proposed Thermal Power Plant Cooling Water Intake Structures rule and proposed Coal Combustion Residuals rule are projected to cost about $384 million to $4.6 billion and $2.1 billion annually, respectively.[xvi] In addition, power plants will also be required to invest in retrofits to comply with state and local environmental rules.

[ix] Estimate based on U.S. Energy Information Agency's (EIA) forecasts for new additional capacity, overnight capital costs, and lead time for various technologies.

[x] The Brattle Group, Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada. Johannes P. Pfeifenberger and Delphine Hou, prepared for WIRES -Working group for Investment in Reliable and Economic Electric Systems, May 2011

[xi] IHS Emerging Energy Research, U.S. Transmission Markets and Strategies: 2011-2020. November, 2011.

[xii] Based on per meter deployment cost of $150-$400, MIT, The Future of the Electric Grid. December 2011. 29 million additional meters deployed between mid-2012 and end 2015 is the difference between current 36 million and 65 million IEE forecast for 2015.

[xiii] IEE Report – Utility-Scale Smart Meter Deployments, Plans, & Proposals, May 2012.

[xiv] IDC Energy Insights, North America Utility Industry Top 10 Predictions 2012 Web Conference. December 6, 2011

[xv] U.S. Environmental Protection Agency, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, December 2011, p. 3-14

[xvi] A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability, Northeast States for Coordinated Air Use Management (NESCAUM), Paul J. Miller, August 2012 and U.S. Environmental Protection Agency website, CCR Frequent Questions. http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/ccrfaq.htm#20

Beyond the cost of environmental retrofits for power plants is the cost of parasitic load, which is sometimes overlooked. Parasitic load, or the amount of electricity required to operate the plants' environmental retrofit systems, can be up to 20 percent of the megawatt capacity of a plant, resulting in a substantial fixed cost increase when viewed on a cost per megawatt basis.

Renewable portfolio standards – There is much debate about the role of renewables in the U.S. generation mix. However, there is little debate that renewables (i.e., wind and solar) are not cost competitive today with more traditional generation sources, and that the vast majority of renewables in service or under construction are the result of tax incentives or renewable portfolio standards (RPS).

Twenty-nine states and the District of Columbia currently have RPS with various capacity requirements and timeframes. An additional seven states have enacted RPS policies that set voluntary goals for renewable electricity procurement. Under standards currently in place, the U.S. Partnership for Renewable Energy Finance estimates that 3.62 GW of additional annual renewables capacity will be required to meet RPS targets and solar carve-outs between 2012 and 2020.[xvii]

Post–Fukushima nuclear safety standards – New regulations required by the NRC post-Fukushima will result in some level of additional compliance-related investment at nuclear plants – the magnitude of which is currently being determined by the affected companies.

Interest rates – Substantial amounts of capital will be required to finance electric infrastructure build-out over the next eight years and much of this will be in the form of debt financings.

Interest rates over this eight-year period are difficult to project. However, past rates are well known. For example, the average interest rate for a 10-year T-Note was 4.3 percent from 2004 to 2008, while it has averaged 3.06 percent for 2009 to 2011.[xviii] The rate has fallen to an average of 1.79 percent for 2012 through August. Most would agree that it is very reasonable to assume that the current cost of debt financing is extraordinarily low, and will necessarily rise in the foreseeable future. The questions are only when and how much.

Interest rate on a 10-year T-Note, 2004-2012 (through August)

Source: U.S. Department of Treasury

[xvii] U.S. Partnership for Renewable Energy Finance "*Ramping up Renewables: Leveraging State RPS Programs amid Uncertain Federal Support,*" 2012
[xviii] U.S. Department of Treasury

The numerator – operations costs

Operations costs of all types increase over time if for no other reason than inflationary impacts. Three factors have been identified as those most likely to significantly influence operations costs, beyond inflation, over the next eight years.

Fuel for electricity generation – The current and historic delivered price of the primary fuel sources for power generation are as follows:

Fuel Prices	2011 Generation mix (Percentage)	2012 Projected average ($/mmbtu, unless otherwise noted)	2004 thru 2011 Average ($/mmbtu, unless otherwise noted)
Coal	42.2	2.39	1.91
Natural Gas	24.8	3.38	6.48
Nuclear	19.2	$49.40/lb	$34.38/lb

Source: All data is from EIA as of September 2012, except 2012 projected average nuclear fuel price, which is from UxC.

Natural gas is all the buzz these days, and rightfully so. The abundance of U.S. shale gas and recent technological breakthroughs in the recovery of this resource have increased U.S. annual shale gas production to 6.8 trillion cubic feet in 2011 – more than six times the production level five years earlier. This, in turn, has led to extraordinarily low prices, natural gas being the fuel of choice for most new generation assets, and the development of natural gas exporting capabilities. As of August 2012, the disparity of U.S. prices to prices around the globe was substantial as shown below.

Average Spot Natural Gas Price Per MMBTU[xix] January-August 2012	
United States	$2.50
European Union	$11.43
Japan	$16.91

The extraordinarily low natural gas prices in the U.S. today have clearly helped to offset what would otherwise be rising electricity prices as a result of the capital and operations costs previously discussed.

When and how much U.S. natural gas prices will rise is the subject of much debate. However, it is generally agreed that prices must rise to at least $4.50 per MMBTU[xx] in order to make the production of much of the U.S. shale gas resources economically feasible. This represents a 70 percent increase in the cost of natural gas as compared to the $2.65 per MMBTU average Henry Hub spot price projected for 2012.

Emissions retrofits – The level of investment expected in emissions-related retrofits has been discussed. With this investment also comes significant additional electric plant operating costs; in addition to the parasitic load. The nature of the retrofit will dictate the related incremental cost, but it is generally agreed that these costs will add over 50 percent to the overall operating costs of the facility, excluding fuel costs.[xxi]

New technologies – The energy industry is often labeled as "slow moving." If this is the case, it has much to do with the nature of the investments historically made in procuring, transporting and supplying energy – i.e., very large dollars and very long lives before these assets and resources are depreciated or depleted.

However, arguably the energy industry is at the forefront of new technologies as manifested by organizations like the Department of Energy's national laboratories and the industry's Electric Power Research Institute and Gas Technology Institute. Most notable are recent technological advancements in hydraulic fracturing, smart grid, solar manufacturing, and battery storage. Each of these advances is designed over time to increase efficiency, and as a result reduce operations costs.

What technological breakthroughs will come next is unknown. What is known is that new technologies will eventually reach a price point where they become economic (or are subsidized for a period of time for the "greater good"). Regardless, it is reasonable to conclude new technologies will decrease the cost of electricity consumed per kWh between now and 2020. The questions are how soon and how much.

[xix] World Bank, "Commodity Price Data," September 2012

[xx] Based on average prices for Haynesville, Fayetteville, and Barnett. Sources: Tim Roberts, *Ethylene – Good Today, Better Tomorrow – A Year Later, Goldman Sachs Chemical Intensity Day*, Lyondellbasell, March 2012

[xxi] Based on a sample 300 MW coal fired power plant and investment costs converted to $/kWh using a 15 percent fixed charge rate and 60 percent capacity factor. Source: Jim Lazar and David Farnsworth, "Incorporating Environmental Costs in Electric Rates," Regulatory Assistance Project (RAP), October 2011, p.15

The denominator – kilowatt hours consumed

From 1949 to 2007, U.S. consumption of electricity has risen in all but three years (1974, 1982 and 2001). The trend since the most recent recession has been as follows, according to EIA data. This six-year period includes, for the first time, a year-over-year decline in consumption for two consecutive years.

U.S. Electricity Consumption 2007-2011

Year	Billion kWh Consumed	Year Over Year Change (%)
2007	3,882	-
2008	3,857	(0.6)
2009	3,716	(3.7)
2010	3,879	4.4
2011	3,851	(0.7)
Projected 2012	3,860	0.2

Source: EIA Electric Power Monthly

The specific reasons for year-to-year changes vary from utility to utility (the wires companies), and are the source of internal discussion and debate. Several recent contributing factors are known. The recession resulted in decreased demand for electricity in both the consumer and business sectors, especially notable in 2009. Also, generally mild summer and winter weather across the U.S. contributed to decreased demand in 2011.

What can reasonably be assumed about the denominator going forward?

Weather patterns – Weather is a big unknown variable from year-to-year and has the potential to result in feast or famine. But, over time, the consistency of the denominator generally allows for "weathering the occasional storm."

U.S. economy – An improving U.S economy will result in the return of some electricity demand from consumers and businesses that was lost in the recession. However, most agree there has been some level of "permanent demand destruction" as a result of the recession; maybe more so in the business sector than the consumer sector. In light of the impacts on demand of a mild summer and winter in 2011, the question still remains as to how much temporary demand loss is still pent up and will return with more normal weather.

Demand growth – New sources of demand for electricity will result in incremental increases in the denominator. Examples could include increased electronics in the home, new computer server farms, growth in demand for electric vehicles and incremental water resources management requirements (desalination, irrigation, and treatment). The potential resurgence of the U.S. manufacturing base as a result of the competitive advantage created by low natural gas prices, largely associated with shale gas, could also result in increased electricity demand.

Technology – Technological advances in energy efficiency will permit electricity customers to "do the same with less." All other things being equal, this will result in a decrease in the denominator.

Customer behavior – The single most important and complex factor impacting the denominator in the future is likely to be the attitudes and behaviors of consumers and businesses when it comes to how they choose to consume electricity. Studies conducted by Deloitte in early 2011, and again in early 2012, suggest that there are changing electric customer trends that challenge conventional wisdom about the level of demand growth, if any, for the foreseeable future. Consider the following Study findings for consumers and businesses.

Consumers – The Deloitte reSources 2012 Study [xxii] was conducted of over 2,200 demographically-balanced household decision makers for utility services. The Study found:

- In 2012, 83 percent of consumers reported they took steps to reduce their electricity consumption – up from 68 percent in the 2011 Study.
- The primary steps taken were behavioral in nature – turning off lights (78 percent), shutting down electronics when not in use (65 percent), adjusting the thermostat in the summer and winter (61 percent), and changing over to compact fluorescent lights (60 percent).
- While interest in purchasing smart energy technologies is relatively low, it is noticeably growing, with younger adults clearly more receptive to making the investment.

[xxii] Deloitte Development LLC, Deloitte reSources 2012 Studies: Insights into Corporate Energy Management Trends and Insights into Emerging Trends of Energy Customers. May 2012

Businesses – Deloitte's 2012 Study also examined business activities and was conducted of over 600 companies with greater than 250 employees. It found that:

- 90 percent of U.S. businesses have set goals focused on managing electricity usage.
- Of these companies, 85 percent cite reducing electricity costs as essential to staying competitive – up from 76 percent in 2011.
- As to reduction targets and accomplishments, the average target is a 23 percent reduction in electricity consumption over approximately a 3.5 year period.
- 35 percent of businesses report some level of self-generation of electricity with another 17 percent planning to do so in the future.
- While businesses have aggressive hurdle rates and payback periods for energy efficiency related investments (21 percent and 3.9 years on average), an upward movement in electricity prices could well justify an incremental level of "economic" investment in energy efficiency.

It is also important not to ignore the "business" that consumes the most electricity in the U.S. – the Federal government.

In 2005, the Federal government began taking a number of actions to both reduce energy intensity and increase the use of renewable energy through either procurement or self-generation. Notably, Executive Order 13423 issued by President George W. Bush in 2007 calls for a decrease in energy intensity at Federal facilities by 3% annually or a total of 30% by the end of fiscal year 2015.[xxiii] Fiscal year 2003 is used as the baseline for measuring actual results.

Some government agencies have in fact established their own goals that are more aggressive than the Executive Order mandate in terms of magnitude of reduction or timeframe. For example, the Department of Defense (DOD) has set a series of goals which reflect a 21 percent reduction in DOD facility energy intensity by 2012 and 37.5 percent by 2020, also using a baseline year of 2003.[xxiv] The DOD currently estimates that it will actually achieve a 24.4 percent reduction by 2012 and 43.5 percent reduction by 2020. In the area of renewable energy, the DOD has set targets that include renewable energy percentage consumption of 12 percent in 2012 and up to 20 percent by 2020.

At a minimum, these findings give pause to the currently forecasted growth in electricity consumption in the U.S. A review of the EIA's forecasts since 2009 of growth in annual electricity consumption to 2020 is in itself also revealing. The forecasted compounded annual increase in consumption through 2020 is still positive, but declining.

Forecast Year	Percentage Annual Increase in Consumption to 2020
2009	1.1%
2010	1.3%
2011	0.96%
2012	0.73%

Source: EIA Annual Energy Outlook, 2010-2012

xxiii U.S. Environmental Protection Agency web site http://www.epa.gov/oaintrnt/practices/eo13423.htm

xxiv U.S. Department of Defense, Strategic Sustainability Performance Plan, FY2011. http://www.acq.osd.mil/ie/download/green_energy/dod_sustainability/DoD%20SSPP%20Public_2011.pdf

The big picture

In the spirit of keeping this analysis simple and straightforward, the graphic below portrays the likely implications of these emerging trends and factors on the value of the variables in the equation.

The Math at Work

The numerator – capital costs

- **New generation** ↑
  – Aging plants
  – Early retirements
- **New transmission and distribution** ↑
  – Reliability
  – Smart grid
  – Renewable portfolio standards
- **Environmental – Emissions restrictions** ↑
  – Capital retrofits
  – Parasitic load
- **Interest rates** ↑

The numerator – operations costs

- **Fuel** ↑
  – Natural gas at historic lows
- **Emissions retrofits** ↑
- **New technologies** ↓

The denominator – killowatt hours consumed

- **New sources of demand** ↑
- **Impact of Recession** ↔
- **Efficiency technology advances** ↓
- **Distributed generation** ↓

This exercise is about the direction of the variables, not the absolute amounts. Regardless, the big picture view is compelling – the numerator is going up and the denominator may well be going down over time ***for the first time in the history of the U.S electric power industry***. And, herein lies the dilemma:

The Dilemma

$$\frac{\text{Increased Costs}}{\text{Decreased kWh Consumed}} = \text{Higher Cost Per kWh}$$

If this is indeed the "new" math, a number of questions are raised.

- Will rising electricity costs, and prices to customers, lead to further decreases in the denominator, leading in turn to even higher costs per kWh? If so, how soon and how high will electricity costs rise – and how much will geographic differences impact one electricity company versus another?
- Will the price to individual consumers reach a point of elasticity and invoke even greater end-user investment in energy efficiency?
- Will there be a wave of new, economically priced technologies designed to enable greater consumer and business control over their electricity consumption?

The actual math will be very company specific. Not only will it differ between merchant generators, transmission and distribution utilities, and integrated utilities; the results can likewise be expected to vary significantly from company to company in the same sector. That is because the factors influencing the variables may differ widely and will change over time.

As companies "do their own math", counting on historical trends and experience should be approached with caution. Increases in the real price of electricity to customers are a new phenomenon, the significance of which cannot be ignored. As electricity likely becomes a larger percentage of disposable household income and a larger percentage of business operating costs, future customer attitudes and behavior may change significantly.

Avenues to evaluate

What happens if companies do not like their "new math"? The logical answer is to change the math. That is, what factors influencing the variables in the equation can be addressed and influenced in a meaningful way over an acceptable time frame and level of associated risk? The discussion that follows is not intended to be all inclusive; nor is a value proposition being placed on any particular course of action. Each company must evaluate these and other alternatives in light of their own math and circumstances.

Reduce the numerator – Based on past practices, the first area likely to be examined is managing the numerator by reducing or deferring controllable costs. Companies need to seriously challenge how much time they are really buying and just how far these efforts really go in changing the math in any significant way.

Moving the needle here in any meaningful way may require something closer to a "life event." This could involve a merger or acquisition, where significant synergy savings are achieved. Or, it might involve "strategic" dispositions, where the value of an asset or a subsidiary is actually greater in the hands of another party that can reap associated synergy savings. In this case, the enhanced cash position and balance sheet of the selling company could be used to acquire different electric assets or businesses that create synergy savings, or could be used to invest in new revenue streams (discussed later).

Change the regulatory paradigm – The price that customers pay for electricity is at least in part, if not entirely, determined through the utility ratemaking process. The regulatory construct varies from state to state and from a Federal perspective, but each construct has some level of latitude in fulfilling its mission to ensure that electricity is safe, reliable and reasonably priced. Recently, the electricity industry has witnessed a number of structural changes to the regulatory paradigm including deregulation of generation, decoupling of electric rates, renewable portfolio standards, and demand response programs – each being evidence that a level of latitude exists.

The pros and cons to these and other initiatives may have been previously evaluated against the backdrop of the "old math." Now may well be the time for utilities, policy makers and regulators to revisit the math, and evaluate mutually acceptable solutions and outcomes. Taking the journey with the regulators will likely be the path of least resistance.

Grow the denominator through new regulated revenue streams – A number of potential opportunities may exist. For example:

- What is the utility's value proposition to businesses that invest in on-site generation?
- Do opportunities exist in residential and business on-site renewables and electricity storage?
- What is the future of the electric vehicle and where does the utility add incremental value beyond transporting and selling the electrons?
- Where can electricity be part of the solution to a growing future problem, such as water scarcity?

While these and other areas may offer new or increased revenue streams, potential policy and regulatory constraints must be evaluated. Where such constraints cannot be overcome, an alternative may be to create unregulated revenue streams in some of these same areas.

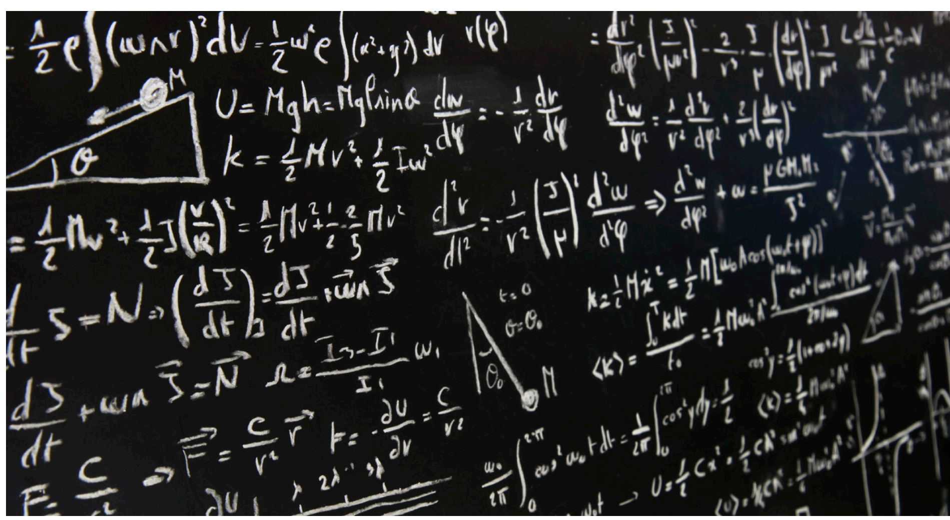
Regardless, electric companies should challenge themselves as to how well they really know their customers; and likewise, how well their customers really know them. The Deloitte reSources 2012 Study reveals that there are measurable differences in the attitudes and practices of household electricity consumers based on certain demographics that extend beyond just income, education and geography – particularly as it relates to age. It is also noteworthy that when it comes to choosing an electricity provider, the vast majority of consumers trust "word of mouth" (relatives, friends, work associates) much more than they do electricity providers.

Change the business model – Over the longer term, companies may find that the answer to the equation is still simply not acceptable. In this case, companies will be challenged to change the operating model of their business. This may seem like a drastic course of action, particularly given the checkered track record the industry has experienced with diversification and globalization efforts in the past. However, the global marketplace and the energy landscape have changed, and will continue to change, and this suggests a reevaluation of viable future business models. There will be pros and cons to the various alternatives, and the level of risk is likely to increase the further a company stretches beyond its core competencies.

Business strategies to be considered might include:

- Use the strength of the current balance sheet to invest in or outright purchase new unregulated revenue streams and potentially diversify the company's overall marketplace risk.
- Evaluate (or reevaluate) opportunities behind the customers' meter for both new regulated or unregulated products and services. Consider how electricity can be bundled with other services.
- Ride the technology wave. There is a high probability that any new technology will rely directly on electricity "to work." Customer acceptance of new technologies likely results in the creation of new customer demands or needs, and providers of electricity may be in the best position to fill some of these needs. The recent expansion of Best Buy's business to include in-the-home technical consultation (i.e. Geek Squad) is an example. Best Buy acquired "The Geek Squad" in 2002 as a way to expand its business services and differentiate the company from low priced competitors and online retailers. While the early focus was on computer services, as consumer demand for electronics services grew, so did the need for technicians to provide consumer consultation. Geek Squad has expanded its services to include TV, home theater, car audio, and gaming set up and services, among others.[xxx]
- Consider future business structures that help calibrate the level of risk to the level of opportunity. These could include joint ventures (with domestic and international partners) and public-private partnerships.

These examples are certainly not all inclusive or necessarily mutually exclusive. However, they can serve as a starting point for more in-depth analysis and evaluation.



[xxx] Best Buy 10K reports, 2003-2011.

Conclusion

The stated objective of this paper was to provide a common framework to initiate or advance the discussion between electricity company management and their stakeholders – including their Boards, policy makers and regulators – about the future state of their business in light of two emerging trends. The trends are rising capital investment requirements combined with moderating or potentially declining electricity demand and consumption. To the degree electricity company managements find this paper to be a useful tool as they address their companies' future state, the paper has achieved its objective.

The U.S. electric power industry has a long history of success and achievement. It has faced its share of challenges and adversities, and through its ingenuity has weathered the storms and consistently improved its track record of providing safe, reliable electricity to businesses and consumers. There is no reason to believe the same will not be true for the next eight years and beyond. However, with respect to demand for its basic product, the industry could very well be navigating uncharted waters – in the form of significantly rising costs to produce and deliver a unit of product in the face of consistently flat or declining electricity consumption.

Against this back drop, this paper suggests that electric companies of all types will be required to rethink their strategies, if for no other reason than the fact that their "peer" companies are likely going through the same exercise. It has been suggested here that this "rethink" include consideration of such options as: new regulatory structures and initiatives, development of new revenue streams, and consideration of innovative business models. The more traditional business models that have served the electric power industry so well in the past simply may not be enough this time – the time for true innovation in the electricity sector may have arrived. By the application of insight and ingenuity, when the year 2020 comes, the successful electricity company may look very different from the electricity business as we know it today.

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