When Unreliability Meets Uncertainty
Roy Nersesian, Monmouth University, NJ, USA

AUTHOR BIO

AUTHOR ADDRESS
Prof Roy Nersesian, MBA
Leon Hess School of Business
Monmouth University
West Long Branch, NJ 07764
E-mail: rnersesi@monmouth.edu
Tel: 973-762-8604

Professor Nersesian is a professor at Monmouth University in NJ, USA. He wrote Energy Economics: Markets, History and Policy published by Routledge Publishing in 2016 (www.routledge.com). He has written several manuals on building @RISK simulation models including Energy Risk Modeling published by the software provider Palisades. He also sits on the board of directors for the International Journal of Risk & Contingency Management.

ABSTRACT

Solar and wind are unreliable sources of energy. A wind farm offshore Europe can supply the power needs of one million households, yet there have been days when total power output couldn’t heat water for a cup of tea. Several years ago, there was an eclipse over Europe during calm weather reducing renewable (wind and solar) power to nil – without 100% backup, the lights would have gone out.

Electricity demand is uncertain, but its uncertainty can be bracketed within known parameters based on an analysis of past demand including a projection for growth. Meeting uncertain demand with reliable supply (fossil fuel, nuclear, hydro except in dry seasons) is the normal course of business for an operating utility. Matching up unreliable supply with uncertain demand is a newly emerging trend with the advent of renewables. At first, when solar and wind made minute contributions to satisfying electricity demand, the challenge was manageable. The challenge is becoming more prominent with the growth in the contribution of solar and wind to electricity supply.

This chapter describes the risk of matching unreliability with uncertainty via a simulation of a utility with a notable commitment to renewables. Upon measuring risk, means to mitigate that risk will be covered.

Key words: Wind power; solar power; renewables; utility business plan; utility strategy; simulation; risk modeling; risk mitigation

GROWING IMPORTANCE OF RENEWABLES
Figure 1 is the growth in actual wind output in terawatt hours for select nations with the largest installation of wind turbines, not to be confused with installed capacity.\textsuperscript{1}

![Wind Output](image)

**Figure 1: Wind Energy Output**

Wind is a rapidly growing renewable with China and US playing dominant roles with the remaining five nations contributing about as much as China and US, but not growing as fast.

BP Energy Statistics allows one to measure the difference between actual output and rated capacity. Rated capacity for US was 82.45 gigawatts in 2016. If this were a fossil fuel plant utilized at 95% for 24 hours per day for 360 days per year, the output would have been 676.7 terawatt-hours. Actual terawatt-hours was 228.8 terawatt-hours, or an average utilization of 34% versus 95% for fossil fuel base load plant.

Figure 2 is the corresponding chart for solar, also showing rapid growth, but at about half in magnitude of wind output.
China and US have about equal outputs with Japan having a significant share of solar output, expanding at a rapid pace. Taking solar output for the US in 2016 of 40.3 gigawatt of power and comparing with fossil fuel utilization of 95% X 24 hours/day X 360 days/year is a hypothetical 330.7 terawatt-hours versus actual output of 56.8 terawatt-hours or an effective utilization rate of only 17%. But this is an unfair measure as solar only supplies energy during the daylight hours. A better measure would be a natural gas plant operating 12 hours per day, and on this basis, utilization rises to 34%, comparable to wind. An economic comparison of solar to fossil fuel should also be based on a natural gas plant operating 12 hours a day supplying daytime power. Comparing wind with a coal burning plant operating 24 hours per day and solar with a natural gas plant operating 12 hours per day places their utilization potential on the same level. Comparative economic analysis for wind and solar should also be centered on base load for wind and daytime load (12 hours) for solar. Some may feel that a fewer number of hours should be used; but whatever the time element, it should be consistently applied both to performance and economic analysis.

Figure 3 is the respective shares of solar and wind in satisfying total electricity generation.
Figure 3: Respective Shares Solar and Wind

Whereas China is a major producer of solar and wind energy, yet they only contribute 5% to total electricity supply with solar being only a small portion compared to wind. The same observation holds for the US with a combined contribution of solar and wind being about 6%. India is 4% renewable centering on wind whereas Japan is nearly 6% renewables relying almost exclusively on solar. However in Europe, the picture is quite different. Whereas Europe appears to lag China and US in terms of magnitude of output, but in terms of relative shares of total electricity supply, solar and wind play a much more dominant role. Solar and wind combined contribute 18% to satisfying German electricity demand, 23% in Spain, and 14% in UK with wind dominating over solar even in sunny Spain.

In local regions, the contribution of renewables is far greater. Mecklenburg-Vorpommern, bordering Poland and Baltic Sea, produces 5 terawatt-hours of electricity that actually exceeds electricity demand mostly from onshore and offshore wind farms and biomass. Schleswig-Holstein, bordering Denmark and North and Baltic seas, reached 100 percent renewable electricity with biomass accounting for 46 percent, 44 percent for wind power, and 10 percent other. Biomass in northern Europe is mainly waste from lumbering operations, but may also include burning combustible household, commercial and industrial waste. Considering biomass a reliable source of energy, about half of renewable electricity generation is at the whim of the wind.

North Dakota is the leading US state in renewables generating 20% of its electricity from wind, New Hampshire also generates 20% from a combination of wind and biomass (Vermont is higher at 25%, but its chief source of renewables is Canadian hydro). Iowa is at 26% renewables from a combination of hydro and wind, the same sources that power Idaho 30%, Montana 34%, and South Dakota 35%. Maine is 38% hydro and biomass, Washington 47% wind, biomass, thermal sources, and Oregon 49% mainly hydro plus wind. Hydro and biomass are both reliable sources of energy, so that the exposure of these states primarily to the whim of the wind is more limited than what the statistics suggest. Various states in the US have Renewables Portfolio Standard (RPS) of which California has the most aggressive requirement of half its electricity
generated from wind, solar, geothermal, and biopower by 2030. In June 2017, serious consideration was being given to revising the California RPS to 50% renewables by end 2026, 60% by 2030 and 100% by 2045. In 2016, California derived 27% of its energy from renewables mainly solar, hydro, and wind.

Solar statistics are not straightforward as are other energy sources. Solar panels are commonly added by individuals to the roofs of their homes. Power generated by the utility is exactly what it says, power generated by the utility. Solar power statistics may include private installations of solar panels, but often they don’t. Under these circumstances, a utility may be underestimating the contribution of solar by counting only its installations, not those privately owned. When this occurs, actual solar output is being underestimated.

TRADITION IS DEAD WHERE RENEWABLES PREVAIL

The traditional model for utilities for electricity demand mimics human activity as it affects electricity consumption. It consists of night time base load augmented by variable daytime load. Coal, nuclear, and where available hydro, essentially operating 24 hours a day supply base load. Variable load is handled primarily by natural gas plants that operate anywhere from 2 to 12 hours per day. Hydropower is used for both base and variable load in areas of plentiful supply.3

Originally all generating equipment was owned by the utilities and the retail electricity rate reflected total operating and capital costs. It was felt that the structure for electricity rate setting promoted a penchant for utilities to over expand their capital base in order to enhance their earnings and perhaps not rigorously enforce operational efficiency since all costs were passed to the rate payer. Deregulation or liberalization gave independent power producers (IPPs) access to utility customers to introduce an element of competition in the utility business. Rates which were administered based on cost became market oriented by establishing a spot and wholesale market for electricity at particular nodes in the electricity distribution system. These rates, based on supply and demand, became the negotiation basis between utilities and IPPs to add generating capacity to handle variable load. Daytime rates were higher than base load reflecting time-limited variable demand that might range between 2-12 hours per day. Rates for natural gas plants had to cover their fixed capital costs regardless of their operating time. IPPs sought contracts depending on their appetite for risk. A common strategy was to enter into contracts with utilities that would cover their fixed costs, thus assuring creditworthiness for issuing long term debt. The remaining operating time would be in the spot market, which would determine the profitability of the equity investment.

The challenge today is that significant additions of renewables, particularly solar power is converting the daily electricity demand profile for fossil and nuclear plants from a camel with a hump on its back to a duck with a swagged back. Figure 4 is demand less renewable sources, which is demand for fossil fuel and nuclear. Assuming no nuclear power, Figure 4 illustrates the conversion of peak daytime power from a camel’s hump to a duck’s back as a consequence of significant increases in solar power capacity both by utilities and their customers. Solar power generated by individuals cuts back on utility output during times of peak load demand, which for
the most part corresponds to peak solar supply. Whether solar installations are owned by utilities or individuals is not material, the impact on fossil fuel demand is the same.

![Who gets the bill?](image)

**Figure 4: Duck’s Back Power Profile**

One of the consequences of renewables as it grows in importance is that it destroys the traditional utility model. The contribution of wind and solar during the daylight hours not only covers peak load demand, but can also prompt cutbacks in base load generation. This happened in certain regions in Germany under favorable weather conditions for solar power (no cloud
cover) and wind power (wind farms operating at maximum output) that covered 80% of electricity demand. This not only forced shutdowns of variable load natural gas generators, but also forced cutbacks of base load generating plants (coal and nuclear power)!

The implications go far beyond idling natural gas plants, but have rendered the business plan of many IPPs as no longer feasible. Solar and wind powered electricity is low priced becoming the marginal producer because they have no fuel costs and are heavily subsidized. To gain an appreciation of the extent of the subsidies, night time rates from wind farms have turned negative in western parts of the US. This means wind farm operators were willing to pay utilities to take their electricity because the amount they paid utilities to take their electricity was less than the subsidy rates received for operating units. Along with subsidized solar power, renewables have weakened not only the spot market but the entire wholesale market. At times wholesale rates have even fallen below base load rates. Traditional fixed term contracts with IPPs are no longer attractive to utilities and the profit potential of operating in the spot market no longer exists. A weak wholesale rate market means that IPPs and utilities are not earning an acceptable return on their past investments to the extent that they are not covered by contracts to utilities. This has caused some IPPs to fail and utility write-off of hundreds of billions of dollars of investments in power generating capacity on a global basis. An example of what is going on is the recent financial collapse of GenOn:

NRG's purchase of GenOn in 2012 created the largest competitive power producer in the nation, Power Magazine notes, but the company has been "crippled" by low prices in wholesale power markets across its territory.

GenOn owns 32 plants across 18 states, with more than 15 GW of capacity. Its power mix includes 61% gas, 27% coal, and the balance oil.

Low power market prices are a concern across the nation, with generators blaming low natural gas prices, renewable energy subsidies and greater efficiency. Power producers say the low prices could cause plants retire, threatening reliability. Others argue that markets are simply experiencing a glut of natural gas capacity, and some plants will have to go offline to boost prices.5

One might conclude that the days of fossil fuel, and nuclear power, are over. Yet nothing could be further from the truth. Notice the abrupt increase in demand in the late afternoon in Figure 4 as the sun wanes in the late afternoon. Alternative power supplies, mostly natural gas, have to be available to take up the slack to avoid blackouts. This generates a strange world where there is no economic incentive to expand variable load fossil fueled generating plants and where existing plants are losing money to the degree that their costs are not fully covered by a contract with a utility, yet they have to exist JUST IN CASE they are needed for cloudy skies, a setting sun, and calm winds. The need to preserve assets that are underutilized, but required to assure reliability of service results in a rate dichotomy where wholesale rates are low and retail rates high. This
split rate system between wholesale and retail rates is the consequence of requiring reliable fossil fuel generators as backup when the sun sets or clouds appear or the wind calms. Even though little natural gas may have to be purchased during daylight hours, the required capital cost in electricity generating capacity even in idle mode must be rolled into the retail rate structure to the degree that utilities own or have contracted for the services of IPPs to supply natural gas generating units. Essentially retail rates reflect the need to have 100% backup of renewables to ensure reliability even though actual usage of these backup plants to generate electricity may be limited.

One can question how can solar and wind capacity be built when wholesale power rates are so low. The answer is twofold. If renewables are required under a RFS, then the utility has no choice but to contract for renewables at any rate necessary to justify the capital investment – in other words, the uneconomic cost to the utility is passed on to the consumer in the form of higher retail rates. The second reason is that renewables are subsidized so it is possible that renewables can operate with low wholesale rates and still be profitable to their investors. This can be seen by wind power operators paying utilities to accept their output in order to earn even larger subsidy payments based on output.

To illustrate the phenomenon of selling electricity at a negative rate, suppose that a wind farm operator is receiving a subsidy of, say, $24 per megawatt-hour output. In order to secure that subsidy, the operator may be willing to pay a utility, say $10-$20 per megawatt-hour, to take its generated electricity and yet enhance its cash flow by accepting a government subsidy based on output. This way the wind farm operator is financially better off, as is the utility for that matter, by selling electricity at a negative rate; all, of course, at the expense of taxpayers.

**CREATING RISK**

This will be accomplished in a number of steps. The first is to model seasonal and daily variations in demand. The second is to model variations in solar and wind output followed by setting up a model to obtain variations in electricity generation both in terms of surpluses and shortages from matching unreliable supply with uncertain demand.6

**Modeling Seasonal Variations for Electricity Demand**

Suppose that demand for electricity is 80% higher in summer than in winter. Selecting an index value of 1.0 for winter electricity demand and 1.8 for summer electricity demand, the Excel normal function can be used to model seasonal demand for electricity on a daily basis. Thus day 1 would have a value of 1.0 and day 180 a value of 1.8. Figure 5 is the portion of the worksheet Annual Variation in spreadsheet RenewSeasonal that derives a seasonal demand curve over a 360-day period.
The formula in cell B5 is: =NORM.DIST(A5, 180, 90, FALSE), which was set up using the normal distribution formula menu in Figure 6.

A mean of 180 was selected for the peak load to occur on day 180 and a standard deviation of 90 was selected to cover 360-day period. “False” was entered to obtain the discrete rather than the cumulative value of the normal distribution. “1” in the formula in cell B5 was changed to “A5” and replicated down for a 360-day period.

Cells C2 and C3 in Figure 5 are the solution cells that create the indicated annual demand from the formula in cell C5: =$C$2*B5+$C$3, which is replicated down the column. Cell G2 is the
absolute difference between the desired value in cell E2 and the calculated value in cell F2. The same relationship holds for cell G3. The objective in cell G4 is for the sum of cells G2 and G3 to be minimized. Attempts to obtain a solution using Excel Solver failed because values for solution variables C2 and C3 would not exactly satisfy the target cell of zero. However Evolver, another @RISK software product, was able to obtain a close-enough solution for the initial values of 180 for cell C2 and 1 for cell C3. Figure 7 is the Evolver menu.

Figure 7: Evolver Menu

Cell G4 is to be as close to zero as possible by varying cell C2 for any value between 0 and 400 and cell C3 for any value between 0 and 10. Practically speaking, the values for cells C2 and C3 were effective for creating a normal curve with a base of 1 to a peak of 1.8 over a 360-day period. The final optimal values for these cells can be seen in Figure 5. If the base load is 2 gW, then base load demand is 48,000 megawatt-hours (2 GW X 24 hours X 1000 mW per gW) and peak load will be 1.8 X base load demand. Figure 8 shows the spreadsheet portion for determining daily demand with 10% daily variation and Figure 9 the annual demand in column D.
Figure 8: Spreadsheet Portion for Annual Demand

<p>| | | | |</p>
<table>
<thead>
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<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
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<td>3</td>
<td></td>
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<td></td>
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<tr>
<td>4</td>
<td></td>
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<td>5</td>
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<td>8</td>
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<tr>
<td>9</td>
<td></td>
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<td></td>
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<tr>
<td>10</td>
<td>1</td>
<td>0.000613</td>
<td>1</td>
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<tr>
<td>11</td>
<td>2</td>
<td>0.000627</td>
<td>1.002863</td>
</tr>
<tr>
<td>12</td>
<td>3</td>
<td>0.000641</td>
<td>1.005772</td>
</tr>
</tbody>
</table>

Figure 9: Annual Demand

This pattern will change with pressing function key F9, which mimics an iteration of a simulation.

**Modeling Seasonal Variation for Solar Output**

Two models are necessary, one for annual variation and the other for daily variation. Modeling seasonal variation depends on the latitude of a location, which determines how far the sun rises above the horizon. New York City has a latitude of almost 41 degrees with a noticeable difference between the height of the sun above the horizon in summer and winter. Europe lies further north.
than New York City – London has a latitude of 51 degrees and Berlin 52.5 degrees, about the same as Labrador’s latitude of 53 degrees. Northern Europe is kept habitable by the Gulf Stream, otherwise the weather would be similar to Labrador. Figure 10 shows that the seasonal difference in solar power output is more dramatic in northern than southern latitudes.

Figure 10: Variation in Solar Power vs Latitude

Approximating for 50 degrees north latitude, suppose that the low point is 2.5 and the high point is 11.8. This means that the equivalent energy influx in winter is only 21% compared to summer. If the summer high point is given a value of 1.0 and the winter low point a value of 0.2, then a normal curve can be constructed using the same methodology for seasonal electricity demand. Figure 11 is the solar supply profile.

Figure 11: Solar Supply Profile
Suppose that a review of weather records shows that clear days occur only 30% of the time in winter and 60% in summer. Figure 12 is the resulting clear day profile employing the same methodology.

Further suppose experiments have been carried out for the degree of diminution of solar power from panels for cloud cover during six hours mid-day in summer. The results have been modeled in Figure 13.
The output of solar plant in Figure 14 incorporates both Figures X.12 and X.13 to obtain annual production of solar power totaling 1500 mW. It is assumed that the solar installations are in the same general area where cloud coverage is consistent throughout the area.\(^7\)

### Figure 14: mWh Output for 1500 mW Solar Farm

Peak energy output during the summer of 9000 mWh is calculated on the basis of 1500 mW X 6 effective hours at full power per day. Figure 14 corrects for the sun not rising as high in winter and incorporates a higher probability of clear days in summer than in winter. Although full power output occurs during the summer season, nevertheless there are periods of up to ten days of cloudy skies reducing output. The average annual utilization when compared to an equivalent sized natural gas plant operating at 95% efficiency for 12 hours per day is around 22%. The lower average compared to the 34% derived in BP Energy Statistics is by having the solar installation in a high latitude region with a high degree of cloud cover during the winter. More southerly locations with clearer skies would raise the utilization rate of solar power.

### Modeling Seasonal Variation for Wind Power

Figure 15 shows the output of an actual wind farm. Notice its rather staccato appearance where wind power output is frequently at 0% or 100% output with a few steps in between. It is also clear that mid-year (summer) wind speeds are less than winter.
Figure 15: Sample Output of Wind Farm

There are 3-10 day periods of calm weather denoted by red bars marking multiple days of calm winds. Wind output has the hallmarks of a four-way light switch with off, dim, moderate, and bright settings. The problem is, of course, no rational person has control over the light switch. For all intents and purposes, the light switch is tended by a mad man. Suppose that a statistical analysis of daily output over a year is summarized in Table 1.

<table>
<thead>
<tr>
<th>Power Level</th>
<th>Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>20%</td>
<td>40%</td>
</tr>
<tr>
<td>25%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>50%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>75%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>100%</td>
<td>50%</td>
<td>30%</td>
</tr>
</tbody>
</table>

Table 1: Seasonal Wind Power Levels

Figure 16 is the seasonal wind power profile for the probability of calm winds varying between 20% in winter and 40% in summer.
Figure 16: Calm Days Profile

Figure 16 is incorporated in Figure 17 showing the wind power generation portion of the spreadsheet.

<table>
<thead>
<tr>
<th>L</th>
<th>M</th>
<th>N</th>
<th>O</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>Seasonal</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Adjusted</td>
<td>Wind</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Calm Days</td>
<td>Power mW</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Random Output</td>
<td>1500</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Number Factor mWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>52.3649092</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>0.2000</td>
<td>0.75</td>
<td>27,000</td>
</tr>
<tr>
<td>11</td>
<td>0.2007</td>
<td>1.00</td>
<td>36,000</td>
</tr>
<tr>
<td>12</td>
<td>0.2014</td>
<td>0.50</td>
<td>18,000</td>
</tr>
<tr>
<td>13</td>
<td>0.2023</td>
<td>0.00</td>
<td>0</td>
</tr>
<tr>
<td>14</td>
<td>0.2029</td>
<td>0.75</td>
<td>27,000</td>
</tr>
</tbody>
</table>

Figure 17: Wind Generation

Column L is the percentage of calm days starting out at 20% in winter peaking at 40% in summer. Column M is a random number to determine the wind power factor. The formula in cell N10 is:

=IF(M10<L10,0,IF(M10<L10+0.1,0.25,IF(M10<L10+0.2,0.5,IF(M10<L10+0.3,0.75,1))))

Cell L10 is day 1 where the chance of calm winds is 0.2. If the random number is less than L10 (or 0.2), then the wind power factor is zero. If the random number is less than 0.3, then the wind speed factor is 0.25. The chance of this happening is .1 or 10% because the probability of being
less than 0.2 has already been taken into consideration. If the random number is less than 0.4, then the wind speed factor is 0.50 (10% discrete probability); and if less than 0.5, then 0.75 (again 10% discrete probability), otherwise 1.0. In this case the chance of a wind speed factor of 1.0 is 50%. During the summer when the chance of calm winds is 40%, the chance of a wind speed factor of 1.0 is 30% with 10% each for wind speed factors of 0.25, .50, .75. At full power output for a 1,500 mW wind farm, mWh output will be 36,000 (1500 mW X 24 hours/day X 360 days per year) as illustrated in Figure 18.

![mWh Output 1500 mW Wind Plant](image)

**Figure 18: mWh Output for 1500 mW Wind Farm**

Comparing Figures X.18 and X.15 shows a reasonable proxy for using an essentially discrete probability distribution as a substitute for reality. Of course a larger assortment of intermediate wind speed factors could be incorporated in the formulation. Of particular note is the occurrence and duration of times of zero wind speed factors when wind speeds are too low to generate electricity. The frequency and duration of times of zero output are fairly comparable between reality in Figure 15 and the simulated output in Figure 18. The average wind utilization generated a mean output factor of 0.31 compared to an average utilization factor of 0.95 for a fossil fuel plant. The mean utilization factor is 3 percentage points less than that calculated from BP Energy Statistics. Relying on nameplate data or total installed capacity for solar and wind for planning purposes would significantly overstate actual output. Figure 19 compares the unreliability of renewables to the uncertainty of demand.
The curvature of renewable supply may not be as great as one might expect from the seasonality of solar output because the peak solar output of 9,000 mWh when added to the wind output of 36,000 mWh is 45,000 mWh versus a winter lull of, say 2,000 mWh for solar and 36,000 mWh for wind or a total of 38,000 mWh. Thus the daily peak output of renewables are cycling between 38,000 and 45,000 mWh on a seasonal basis.

SIMULATING UTILITY OPERATION

Figure 20 shows the remainder of the spreadsheet after modeling solar and wind output.\(^8\)
Column Q is total renewables production, column R output of 1 gW of base load supply, column S total demand less renewables and base load, column T is the shortage of capacity satisfied by natural gas, column U the number of 100 mW natural gas plants that would be required, and column V surplus electricity production with all natural gas plants idle.

Figure 21 shows the nature of demand less renewables and base load. A shortage would have to be supplied by natural gas plants whereas a surplus would have to be disposed of; i.e. full output of renewables would not be tapped.

![Figure 21: Single Iteration of Demand Net of Renewables and Base Load](image)

A simulation was run with the result shown in Table 2.

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>27</td>
<td>30</td>
<td>31</td>
</tr>
<tr>
<td>Average utilization natural gas generators</td>
<td>32%</td>
<td>36%</td>
<td>41%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>4.2</td>
<td>6.6</td>
<td>9.1</td>
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<tr>
<td>Annual days surplus generation</td>
<td>45</td>
<td>65</td>
<td>86</td>
</tr>
</tbody>
</table>

Table 2: Simulation Results for Base Load 1 gW

The logical variable at this time to analyze system performance is reducing the base load of coal and nuclear power in favor of natural gas plants. Table 3 is the results for a base load of 0.9 gW.
The required number of natural gas generators climbed by one with a small improvement in utilization. However, surplus generation measured both in terms of average days demand and annual days of surplus generation fell. The reason for this is that a reduced capacity of base load plant capacity creates a greater reliance on variable load plants. A larger number of variable load (natural gas plants) means that fossil fuel plants can be reduced to a lower level of operation to absorb more of what was surplus electricity generation. Table 4 further reduces base load capacity to 0.8 gW.

<table>
<thead>
<tr>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
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<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>29</td>
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<tr>
<td>Average utilization natural gas generators</td>
<td>35%</td>
<td>39%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>1.6</td>
<td>3.0</td>
</tr>
<tr>
<td>Annual days surplus generation</td>
<td>28</td>
<td>44</td>
</tr>
</tbody>
</table>

**Table 4: Simulation Results for Base Load 0.8 gW**

System performance continued to improve with higher utilization of an increased number of required natural gas plants (33) with further diminution of surplus generation in terms of average days demand and days of surplus generation. Table 5 is for a base load capacity of 0.7 gW.

<table>
<thead>
<tr>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>30</td>
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<tr>
<td>Average utilization natural gas generators</td>
<td>37%</td>
<td>41%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>0.7</td>
<td>1.7</td>
</tr>
<tr>
<td>Annual days surplus generation</td>
<td>15</td>
<td>32</td>
</tr>
</tbody>
</table>

**Table 5: Simulation Results for Base Load 0.7 gW**

Again, the ability to cut back on fossil fuel generation output provides the incremental demand to absorb surplus electricity generation by renewables during favorable weather conditions for solar and wind generation. Table 6 is for a base load capacity of 0.6 gW.

<table>
<thead>
<tr>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>31</td>
<td>34</td>
</tr>
<tr>
<td>Average utilization natural gas generators</td>
<td>38%</td>
<td>42%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>0.2</td>
<td>0.8</td>
</tr>
<tr>
<td>Annual days surplus generation</td>
<td>8</td>
<td>20</td>
</tr>
</tbody>
</table>

**Table 6: Simulation Results for Base Load 0.6 gW**
The surplus generation in terms of average days demand is about 1 day meaning that the surplus being experienced during the 20 days of surplus generation has fallen considerably as the capacity to cut back on traditional fueled electricity generators increases. This absorption of surplus generation increases the overall efficiency of the system by reducing waste – that is unusable generation of electricity. Table 7 reduces base load capacity by another 0.1 gW.

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>32</td>
<td>35</td>
<td>36</td>
</tr>
<tr>
<td>Average utilization natural gas generators</td>
<td>39%</td>
<td>44%</td>
<td>49%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>0</td>
<td>0.3</td>
<td>0.8</td>
</tr>
<tr>
<td>Annual days surplus generation</td>
<td>2</td>
<td>11</td>
<td>23</td>
</tr>
</tbody>
</table>

**Table 6: Simulation Results for Base Load 0.5 gW**

Table 7 is for a base load capacity of 0.4 gW.

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>33</td>
<td>36</td>
<td>37</td>
</tr>
<tr>
<td>Average utilization natural gas generators</td>
<td>41%</td>
<td>45%</td>
<td>51%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>0</td>
<td>0.07</td>
<td>0.3</td>
</tr>
<tr>
<td>Annual days surplus generation</td>
<td>0</td>
<td>4</td>
<td>12</td>
</tr>
</tbody>
</table>

**Table 7: Simulation Results for Base Load 0.4 gW**

While probably past the point for a decision by how much to reduce base load for variable load generator; but for record purposes, Table 8 shows the results for a base load capacity of 0.3 gW.

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number 100 mWh natural gas generators</td>
<td>34</td>
<td>37</td>
<td>38</td>
</tr>
<tr>
<td>Average utilization natural gas generators</td>
<td>42%</td>
<td>47%</td>
<td>52%</td>
</tr>
<tr>
<td>Surplus generation in average days demand</td>
<td>0</td>
<td>0</td>
<td>0.04</td>
</tr>
<tr>
<td>Annual days surplus generation</td>
<td>0</td>
<td>0.4</td>
<td>5</td>
</tr>
</tbody>
</table>

**Table 8: Simulation Results for Base Load 0.3 gW**

**RISK MITIGATION**

This paper deals with two risks. The first was dealing with the surpluses and shortages from introducing higher levels electricity generation from renewable fuels (solar and wind). The second is the risk that the conventional utility model for fossil fuel and nuclear investment decision making is threatened by the intrusion of significant contributions of renewable energy to satisfying electricity demand.
Risk of Mismatching of Electricity Supply and Demand

It was shown in this paper that system performance can be improved by transforming base load generation (coal and nuclear) to variable load generation (natural gas). Variable load generation can compensate with additional output as solar and wind power wane and can be cut back sufficiently to absorb any surpluses without wasting electricity from a free energy source. Transformation from fixed to variable load plants may not be that costly for those coal burning plants that are capable of relatively easy modification for burning natural gas. This is not a universal principal: it may be that the design of the coal burning plant is not conducive to transforming to burning natural gas. Then it might be necessary to abandon a coal fired facility and relying on either building natural gas capacity or higher utilization of existing units. Acquiring natural gas units from IPPs in financial distress may be an economic way for a utility to boost its variable load generation capacity.

The financial problems afflicting the Vogtle nuclear plants under construction for Georgia Public Power may well encourage reducing reliance on base load generating units. The bankruptcy of the nuclear plant provider, Westinghouse, is hardly a harbinger of a nuclear renaissance. Maintaining an American tradition of cost overruns and construction delays transforms what should be low-cost electricity into high-cost electricity. This has been experienced by nearly every nuclear plant built in the US. France has succeeded in making nuclear power economical through a series of moves to rationalize construction and operation. But this is not true in US where the construction of each plant follows a unique design and construction procedure eliminating any benefit of a learning curve to reduce construction costs and time. US nuclear plant facilities, mainly built in the 1970s, are in the process of obtaining renewal licenses to extend their lives to 60 years. However some units are being retired because life extension costs cannot be economically justified or the weight of public opinion against nuclear power can no longer be resisted. A tremendous amount of radioactive waste as spent nuclear fuel modules has been accumulated over four decades of operation from over 100 nuclear power plants. Disposal of spent fuel modules now held in temporary storage has yet to be decided and its eventual cost has not been incorporated in the rate structure. It appears that natural gas and renewables will be the logical replacements for nuclear power. Coal for both economic and environmental reasons may not be a major beneficiary, although some “clean coal” plants may be built.

Emphasizing variable load generation at the expense of base load generation does reduce the need to build super-sized storage batteries that don’t exist. Proxies exist as pumped storage and compressed air facilities plus other means of storing electricity. But this does not rule out the necessity for utilities to invest in storage batteries. Battery storage may be necessary to stabilize electricity generation during times of swift changes in cloud cover or wind patterns. The analysis of the optimal size of battery storage to stabilize operations can be addressed by the same general approach taken in this study, not for each day of a year, but for each minute of a day. The model would have to be expanded to take into account the magnitude of surges of electricity into and from the battery. A very large capacitor may have to be attached to the battery to control the magnitude of inflows and outflows.
Risk of Obsolescence of the Traditional Utility Model

Renewables (solar and wind) erode the peak of a camel’s hump to the detriment of fossil fueled (primarily natural gas) electricity generators. Any erosion of daytime peak demand with relation to base load weakens the spot and wholesale markets upon which investment decisions by utilities building natural gas units or contracting for their use through IPPs. This is not to say that weakening of the spot market is bad per se, but it does diminish the incentive for building new capacity. Of course, this is the primary function of the spot and wholesale market. When supply is sufficient for demand, the incentive to expand capacity should be absent. But what if a weak wholesale market is caused by renewables replacing natural gas plants during daylight hours? It is possible for natural gas plants to be built to ensure reliability, but there is no means for utilities and IPPs to economically justify such investments. Weak wholesale prices during the day destroys the profitability of investments made by IPPs and may lead to their financial ruin if they don’t have sufficient fixed rate contracts with utilities to support their financing and other fixed cost charges. Utilities might have difficulty gaining approval for their investments in generating capacity if the wholesale price cannot justify the investment.

However utilities have the right, so to speak, to add capacity to ensure reliability at the expense of rate payers who will see their electricity rates escalate. This is essentially where we are today: low wholesale prices coupled with high retail prices to support natural gas plants whose operation is limited to supporting the reliability of the system, not necessarily for generating electricity. The whole purpose of utilities is to provide low-cost electricity to its customers in a reliable manner consistent with meeting their financial and operating responsibilities. Renewables are turning this equation upside down where utilities are providing high-cost electricity in order to meet the challenge that a significant portion of their generating capacity is invested in unreliable renewable sources. While it is true that the development of a low-cost super-battery of enormous capacity would better fit a world of renewable and fossil fuels, such a battery does not exist. But it is possible to model the uncertainty similar to the approach taken in this paper and be able to assess the optimal electricity storage capacity needed to assure reliability.9

If the traditional utility model is deemed obsolete by virtue of low wholesale prices during times of peak demand, it is not clear what the replacement model should be. It is possible to continue with business on an “As Usual” basis, but it will not be possible to pass the savings of low wholesale prices to the customer until the reliability question is better addressed. This may have to wait the day until low-cost, high-capacity storage for electricity becomes available.

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2 “These States Use the Most Renewable Energy,” Casey Liens, U.S. News, April 22, 2017

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@RISK software contains two optimization programs Evolver and RISKOptimizer described on the provider’s web site www.palisade.com.


9 Nersesian, R., Integrating renewables with electricity storage, using @RISK. Available at Palisade Website: go.palisade.com/WC2016-04NersesianReNew.html