The Impact of Drought on Electricity Supply in North Carolina

by
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Abstract

North Carolina is located within the Southeastern region of The United States, an area which has experienced varying degrees of drought over the last two decades. Water withdrawal and consumption are integral and unavoidable components of the electricity generation process whenever it is fuelled by non-renewable sources of primary energy. It follows from these two statements, that North Carolina - which largely depends on base-load coal and nuclear thermoelectric power generation - will be vulnerable to electricity supply disruptions in times of severe drought. In this report, an attempt is made to quantify the financial or economic impact on privately-owned utility companies as well as the state economy.

The report will cover various issues en-route to quantifying the impact of drought including: identifying areas in the state historically prone to drought, locations of major power plants in relation to these drier areas, electricity generation costs of different powers plants within the state as well as changes in aggregate generation costs under different scenarios when countering the adverse effects of drought.

Major findings include that roughly 5000 MW of baseload generation capacity is situated in especially drought prone regions and that droughts severe enough to result in plant shutdowns occur once in three decades. Economic impact on the state would run well into the hundreds of millions while individual utilities will see lower cost impacts in absolute terms potentially leading to underinvestment in drought-mitigating measures.

These potential economic and financial losses are then used as a basis to explore the possibilities for making investments in less water-intensive technologies for electricity supply. The alternative investment options are then compared to find the most cost effective. Such investments would alleviate the pressure on the state's finite fresh surface water resources while simultaneously mitigating against any drought-induced electricity supply disruptions.

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PROBLEM STATEMENT

With the possibility of drought occurring in North Carolina, electricity utility companies must frequently face the risk of interrupted operations due to lack of cooling water. The problem has not yet received large-scale public awareness because past droughts have not been so severe as to lead to power plant shut-downs. The risk however, is still real and is one under constant monitoring from energy utility companies.

This report aims to evaluate the impact of drought on the supply of electricity in North Carolina. This task has several steps which will be carried out sequentially throughout this report. The steps are as follows:

- Identify areas in North Carolina prone to dry periods
- Find the amount of electricity generation within these dry regions
- Find what proportion of total state generation capacity is affected and what proportion of baseload capacity is affected.
- Find the “threshold” drought severity level at which surface water resources are strained
- Find out the physical indicators that may be used as early warning signals for imminent problems at power generation plants
- Find the probability of these “threshold” levels of drought severity occurring in these regions
- Determine the impact on available capacity should a drought occur
- Determine the *expected* impact to utility companies operating the plants (factoring in the probability of such a severe drought occurring)
- Find out if there is any scope for alternative investment to avoid the adverse impacts of drought

The investment options explored will be limited to renewable energies and different energy efficiency programs. Through exploring these options, we see how much of the vulnerable generation capacity may be compensated or offset using these alternative investments. The amount of electricity generation offset indicates how much the supply-disruption risk is lowered in the event of a severe drought.

1. INTRODUCTION

Ensuring sufficient electricity supply involves considering projected population growth, energy consumption patterns, feasible technologies and in many cases, also available natural resources. Until the recent severe droughts of the Southeastern United States, the impact of water availability – an important natural resource – has not received adequate regional attention in the deliberations around electricity supply.

As a state located in the drought-prone Southeast, this issue is of significance in North Carolina. Widespread precipitation and atmospheric measurements began in North Carolina in the late 1800s and with such data, indices for drought severity may be estimated.[1] Used frequently amongst these is the Palmer Drought Index (PDI) which ranges from -6 to 6 where the higher values indicate wetter periods. According to this data, North Carolina has experienced 4 major dry spells over the last decade as shown in Figure 1. The most recent and severe of these occurred over the first half of 2008 and forced state authorities to contemplate new emergency measures to counter periods of sustained water shortage. (Note: the deep trough associated with the most recent drought is shown toward the extreme right on the graph below)

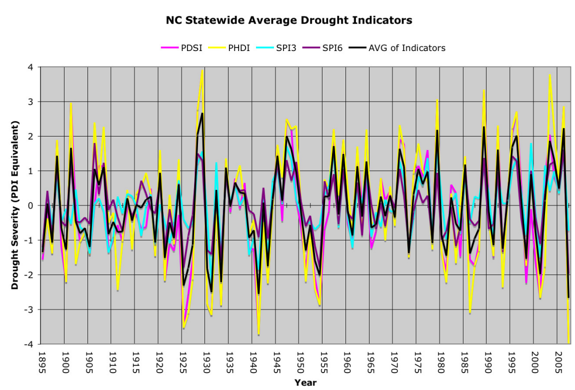


Figure 1: Palmer Drought Severity Index for North Carolina since 1895 [1]

Recent research shows that the severity of the latest drought was exacerbated by rising water demand driven by increased population and excessive water consumption. Coupled to this finding, no statistically significant linkages could be made between dry spells and any meteorological drivers. These results point to internal atmospheric/atmospheric-ocean climate variability as the causal link – a diagnosis in line with the random trend observed over the region for the last century.[2] Such findings suggest that climate change is as likely to increase the strain on water resources in the Southeastern United States as it is to alleviate the problem. In light of this variability, scientists also conclude that the acute water shortages in the region come about in part due to lack of adequate water-related planning to deal with regional climate variability.[2] This merits an exercise where the economic impacts of such dry climatic periods are investigated, such that one has a basis for scenario planning and expenditures on drought contingency measures.

1.1 Clarifying the need for water

In thermal electricity generation, the requirement for water is two-fold. Firstly, water is *consumed* from fresh water sources and irreversibly lost as vapor commonly seen released from cooling towers at conventional thermoelectric power plants. In addition, water is also *withdrawn* and – for the most part – returned to the source water body albeit at a higher temperature in so-called open loop once-through cooling systems. Both of these modes are essential for the proper functioning of thermal electricity generation units. The levels of water consumption and withdrawal will depend on the cooling technology and configurations used at each respective power plant. By 2000 daily water withdrawals by thermoelectric power plants reached 9100 million gallons per day in North Carolina.[3] Total state-wide electricity generation reached 117 000 gigawatt-hours[4] (GWh) in the same year implying that roughly 0.03 gallons of water were withdrawn that year per megawatt-hour generated. This usage rate is an estimate of a state-wide average, it is important to note that water withdrawal and consumption also vary by power plant type and that nuclear and coal plant are the most demanding in terms of water usage. Moreover, nuclear and coal-fired power plants make up all baseload capacity in North Carolina – the most important component of total generation capacity.

Typical monthly electricity generation in North Carolina amounts to between 9 and 14 million megawatt-hours.[5] Over 95% of this amount is produced by electric utility companies with the remainder coming from independent power producers.[4] The dependence on water is aptly demonstrated in Figure 2 where North Carolina ranks amongst the top 10 states in the nation in terms of electricity-related water withdrawals[3], yet does not rank among the highest states in terms of annual precipitation.[6]

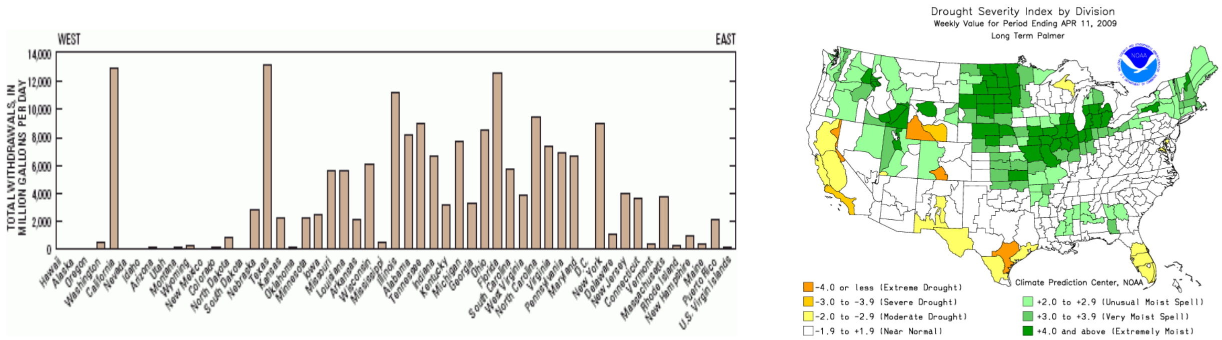


Figure 2: Water withdrawals by State for the year 2000 and Precipitation map for the United States

In addition to the sheer volumes concerned, it is also important to note that this demand comes to bear disproportionately on the surface-water resources. Figures vary by state but North Carolina sources all water for cooling purposes from surface water reserves. The withdrawals of freshwater in fossil fuel and nuclear plants will differ due to their disparate operating temperatures and configurations for cooling systems installed (i.e. closed-loop cooling systems, once-through, dry or hybrid cooling systems). The following diagrams illustrate typical water consumption and withdrawal levels associated with the electricity generation units that dominate the sector in North Carolina.[7]

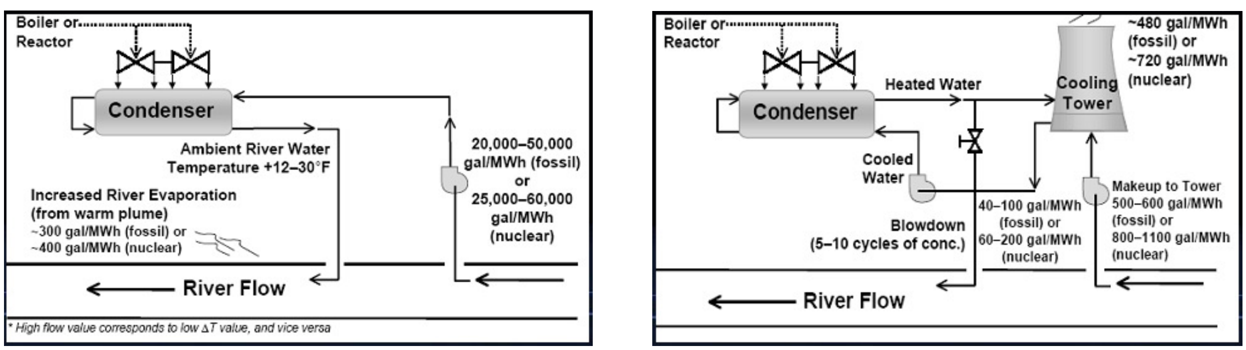


Figure 3: Typical water consumption and withdrawal levels for power plants

1.2 Spatial variation of dry regions in North Carolina

Using the most recent North Carolina drought as a point of reference, we see that water shortages are not uniform over the entire state. For a more detailed overview of the potential patterns of dryness, data from the National Drought Monitoring Service may be used. In addition, data is available on the volumetric flow-rates of each major river in North Carolina from the United States Geological Survey. The rivers fall into watershed regions (see Figure 4 on the next page) which serve as useful boundaries into which to categorize the locations of electricity generation units. The in-state thermal power plants are typically positioned next to a large body of water to ensure sufficient water for cooling duty. Figure 4 also shows how in 2008, the driest portions of the state were towards the mid-section. This implies that it is important to identify which power plants are found in regions of frequent dry spells such that one knows what level of electricity shortage North Carolina may face in the event of severe drought.

Even with historical data on droughts however, it is impossible to predict water availability impacts across different parts of the state. What is possible however is to use historical data to estimate the probability of drought occurring in any one region – thereby highlighting historically vulnerable areas. A "vulnerable area" will be one where:

- A large amount of (base load/intermediate) electricity generation capacity is present.
- A historically-observed, increased propensity to drought is exhibited

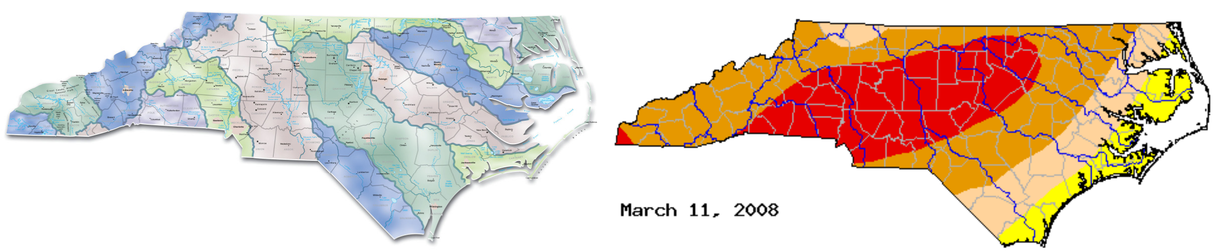


Figure 4: Watersheds in North Carolina (right) and spatial variation of dryness during 2008 drought (left)[8]

1.3 How drought affects electricity prices or overall electricity supply costs

Electricity prices are affected in the event of unplanned constraints on generation capacity. Electricity supply networks are typically fed by generation units in a preferred sequence based on progressively increasing marginal costs of electricity production. The number of each type of power plant within the supply network largely depends on the demand profile characterizing the combination of all in-state electricity consumers. The lowest generation costs are typically exhibited by baseload power plants which operate at or near full capacity at all times – indeed, their low cost structure is in part attributable to this steady, consistent operation. As one looks to generation units with higher production costs, one finds units with the flexibility to respond promptly to rapid fluctuations in electricity demand. In North Carolina the baseload, low-operating-cost power plants are also the ones that consume the most water.

With these baseload plant threatened in the event of a severe drought, there will be upward pressure on the overall electricity price level or – as is the case in North Carolina where there is regulation on prices – net income revenue margins for electricity suppliers will temporarily be reduced.

As long as there is no *prolonged* disruption of water supply there should be no lasting effect on the electricity sector. Protracted water shortages however, as experienced during severe droughts, could adversely affect the electricity sector. Quantifying this impact will form part of this report. The outcome of this task may also inform the decision on whether to invest in alternative technologies which are not as water-intensive.

2. METHODS

The impact of severe drought on the North Carolina electricity sector will be quantified by evaluating the aggregated effect on the profitability of major utility companies and on the state economy. Part of this entails quantifying the amount of electricity generation that must be shifted to natural gas peaking plants or imported from neighboring states to make up for constrained supply. Within a regulated electricity market, cost increases may not be passed on to the end-consumer. Using this approach, we may also see how much utilities would be willing to spend to prevent such financial losses in the future.

The steps in this study have already been listed in the problem statement. In this methods section, we delve deeper into the details of how it is to be done.

a) Identify areas in North Carolina prone to dry periods

Finding areas likely to experience dry periods is done using historical data. No statistically significant drivers have been identified for the occurrence of drought in North Carolina. In light of this, studies suggest that the occurrence of drought is linked to inherent regional atmospheric variability[2] – a random process. This implies that any historical data that is collected will reflect the random nature of this occurrence of drought. The data is expressed using the Palmer Drought Severity Index. The ***Palmer Drought Severity Index (PDSI)*** attempts to measure the duration and intensity of the long-term drought-inducing circulation patterns. Long-term drought is cumulative, so the intensity of drought during the current month is dependent on the current weather patterns plus the cumulative patterns of previous months. Since weather patterns can change almost overnight, the PDSI is formulated such that it can also respond rapidly and ensure reasonable accuracy.[9] Data on this drought index is available at the state level as an aggregated average and also for specific regions within North Carolina. The areas that exhibit frequent low scores on the Palmer Index will warrant close attention. The climate regions are shown in Figure 5:

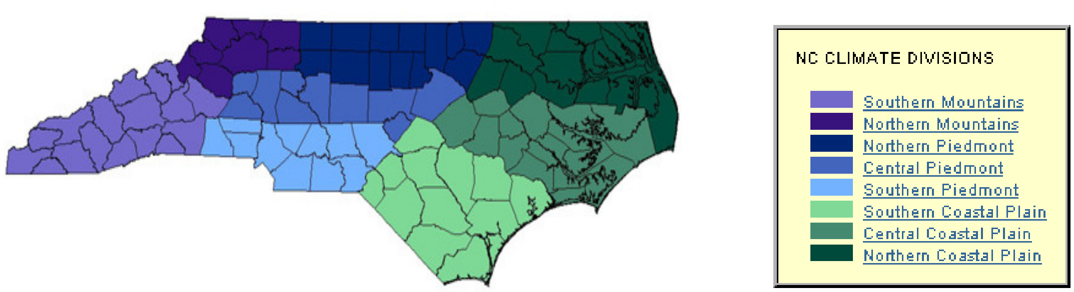


Figure 5: Division of North Carolina into climate regions for Palmer Drought Index measurements

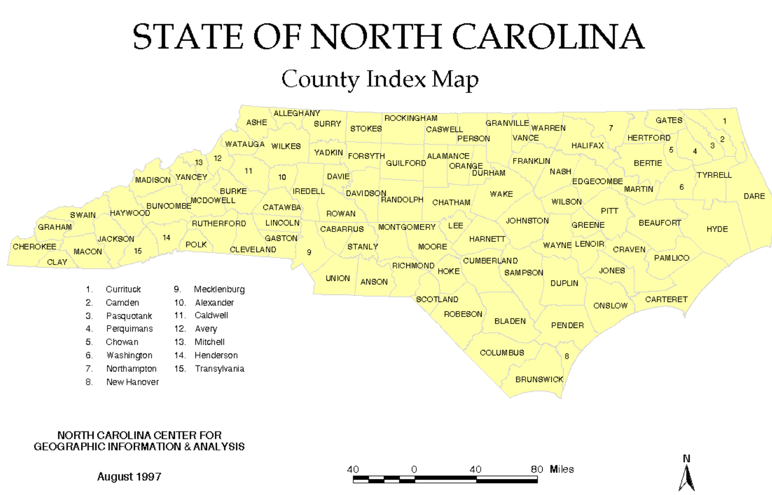
b) Find the amount of electricity generation capacity within the dry regions

This step of the investigation is also relatively simple. Electricity supply in North Carolina is dominated by two utility companies, namely The Duke Energy Corporation and Progress Energy. Both these companies have complete listings of their power plants available to the public. The following table shows all the major power plants in the state as well as their respective locations:

Table 1: List of all baseload/intermediate water-intensive power plants in North Carolina[10]

Power Plant name	**Fuel**	**Company**	**Capacity (MW)**	**County**
McGuire	Nuclear	Duke Energy	2 200	Mecklenburg
Allen	Coal	Duke Energy	1 140	Gaston
Belews Creek	Coal	Duke Energy	2 240	Stokes
Cliffside	Coal	Duke Energy	760	Cleveland/Rutherford
Dan River	Coal	Duke Energy	276	Rockingham
Marshall	Coal	Duke Energy	2 090	Catawba
Riverbend	Coal	Duke Energy	454	Gaston
Lincoln combustion	Oil/Gas	Duke Energy	1 200	Lincoln
Rockingham	Oil/Gas	Duke Energy	825	Rockingham
Brunswick	Nuclear	Progress Energy	1 875	Brunswick
Shearon Harris	Nuclear	Progress Energy	900	Wake
Asheville	Coal	Progress Energy	376	Buncombe
Cape Fear	Coal	Progress Energy	317	Chatham
Lee	Coal	Progress Energy	400	Wayne
Mayo	Coal	Progress Energy	742	Person
Roxboro	Coal	Progress Energy	2 440	Person
Sutton	Coal	Progress Energy	598	New Hanover

The following county map of North Carolina allows one to easily locate each power plant:



c) Find proportion of state generation capacity affected and proportion of base-load capacity affected

This is a combination of steps a) and b). Once the areas prone to dry periods are found, the locations of the major power plants are then superimposed onto the dry regions. The areas that exhibit both presence of large power plants and dryness capture the "affected" or "vulnerable" regions. The amount of compromised capacity is then compared to the total state generation capacity (27000 MW) as well as the total base-load capacity (10000MW to 12000 MW).[10,11]

d) Find the drought severity level where surface water resources are stressed

Identifying the threshold drought severity level where problems occur is done by empirical observation. Data from the United States Geological Survey (USGS) is available on volumetric water flows and water levels for the majority of lakes and rivers in the state. Where one observes a consistent decrease in the water levels in lakes or flow in rivers, the corresponding drought severity level at that time is noted. This is done for each site where a potentially affected power plant is located. This exercise must be done for each individual power plant because surface water bodies in different areas within the state may behave differently even under the same level of drought severity.

e) Find physical indicators used as signals for imminent problems at power generation plants

This task is not central to evaluating the impact of drought but does have practical use for those looking to quickly identify imminent water shortages. It has already been noted that the Palmer Drought Severity Index may be used to find the drought levels at which utility companies should be concerned. Coupled to this, additional indicators may be found that allow use of USGS data in recognizing when a drought is reaching threshold severity. Such indicators would include levels of upstream lakes and rivers. In addition to acting as signals, we may also see – through these indicators – the amount to water that will be available in rivers for cooling purposes. Alternatively, in cases where water is drawn from lakes, we may determine the amount of time available until water depths fall low enough to force plant shutdowns.

f) Find the probability of severe drought occurring in each region

Since the occurrence of drought in the state is a random process, the data on all past Palmer Drought Severity Indices should yield a probability distribution curve which characterizes the random process in terms of an average Palmer Drought Severity Index and a standard deviation. In addition, the data set on the Palmer Drought Index is very large (i.e. weekly recordings dating back to 1895), hence constructing histograms with this data allows one to calculate the probability of each level of drought occurring. Using Microsoft EXCEL, a simple calculation is used to determine the probability of a certain level of drought occurring:

For a Palmer Drought Severity Index of E (with E ranging from -6 to +6)

$$\textbf{Probability (E)} = \frac{\textbf{Number of occurrences in E}}{\textbf{Total number of observations}}$$

To get a practically meaningful result, all the Palmer Drought Indices that have occurred in the past are "binned" into ranges of 0.5 (i.e. occurrences between -6.0 and -5.5, -5.5 and -5.0, -5.0 and -4.5, etc) to yield the probability of a drought severity occurring that is within a given range. This is done for all the regions shown in part a) of this methods section. The regions which exhibit the highest incidence of threshold drought levels will receive closer evaluation.

g) Determining the impact of drought

The financial impact of drought will be found using the increase in generation costs that results from shifting electricity production away from low-costs baseload facilities over to natural-gas fired intermediate and peaking power plants. The increase in production costs happens for 3 reasons:

1. Natural gas fired power plants have higher costs of electricity production
2. Natural gas prices will increase because of higher demand. Demand will come from peaking plants being online for longer periods. Natural gas price increases will be quantified using the price elasticity of demand. A price elasticity measures how sensitive a commodity price is to a change in demand. From the equation below, we also see that the elasticity is defined such that it conveniently yields any projected price increase as a percentage increase from a base price.

$$E_d = \frac{\text{\% change in quantity demanded}}{\text{\% change in price}} = \frac{\Delta Q_d/Q_d}{\Delta P_d/P_d} \qquad E_d = -\frac{d\ln Q}{d\ln P}$$

Where: E_d is the price elasticity of demand

Q_d is the quantity demanded

P_d is the market clearing price

3. Importing electricity from neighboring states (if shortfall cannot be covered by natural gas plants) will be done at the highest peak rates applicable in the state from which electricity is imported.

Having found the per kilowatt-hour (kWh) rise in generation costs by accounting for the 3 points directly above, one then simply multiplies this rise in cost with the total amount of electricity production that is affected during the drought. This is the same amount that will now have to be produced using natural gas peaking plants and/or covered through electricity imports.

Financial impact = Δ electricity generation cost x total electricity generation affected

To simplify assigning production costs to different power plants, the generation units will be grouped based on fuel type. Although some accuracy is lost using this approach, we are still able to see the stage at which the state will have to sustain structurally higher generation costs. In addition to this, major power plants in North Carolina are by-and-large owned by either Duke Energy Corporation or Progress Energy, both of which will have similar costs structures being companies which operate in the same state regulatory environment, run large generation units (i.e. mostly >300 MW), and source fuel from the similar vendors (i.e. coal from Appalachian States and Uranium from The United States Enrichment Corporation).[12,13,14] The electricity generation costs used in our calculation are as follows:[15]

Fuel, operations & maintenance costs:	Coal	\$0.02-0.03/kWh
	Natural gas	\$0.07 - \$0.09/kWh (peaking plants)
	Nuclear	\$0.01c – \$0.02/kWh

Utility companies will bring power plants online in an overall cost-optimizing sequence. Barring complications or bottlenecks in electricity transmission, generation units with the lowest electricity generation costs are brought online first.

h) Determine the expected financial impact to utility companies and the state

Expected financial loss is determined using the impact suffered during severe drought in combination with the probability of that specific drought event occurring. If X is a discrete random variable that takes on value x_i and with probability mass function p(X = x), then for any function g:

$$E\left[g\ (X)\right]=\sum_{i} g(x_i)p(X=x_i)$$

Where: E [g(X)] is the expected financial loss when a Palmer Drought Severity of x_i occurs

g(x_i) is the financial impact sustained if a drought of Palmer Severity Index x_i occurred

p(X = x) is the probability that a drought of Palmer Drought Severity x_i occurs

x_i denotes the Palmer Drought Severity Index

h) Find scope for alternative investment in less water-intensive technologies

To find the potential for investment in alternative technologies, a survey of research papers will be conducted to find the costs of these alternatives. Alternatives must not place any further burden on state surface water resources. Investments considered include wind energy, solar photo-voltaics and various energy efficiency measures. Cost estimates will be found for all these options on the basis of every kilowatt-hour saved or extra kilowatt-hour made available.

The normalized costs of these programs or technologies will then be divided into the total amount of capital funds made available by the utility companies.

i) Constructing the electricity supply cost curve for North Carolina

The supply cost curve allows one to quantify the financial impact of the generation adjustments made during droughts. Forming this curve requires a list of all the power plants in the state together with their respective per kilowatt-hour costs for electricity production.

Since our approximation of electricity supply side costs in North Carolina assumes uniform costs for common power plants types, the *supply curve* exhibits a series of plateaus. The height of each plateau indicates the respective generation costs of each plant type and the width of each plateau represents the amount of capacity at each cost level. The electricity generation costs used in our calculation are listed in part g) of this methods section. The cost supply curve will resemble the one in the Figure 7.

j) Constructing the demand profile curve for North Carolina

Electricity must be supplied in real-time because there is no means for storage. This feature allows one to use data on actual energy consumed or delivered as a proxy for demand. The best resolution found for consumption data is by month and is presented by the Energy Information Agency (EIA). The most recent data found is for 2006 and 2007 and is presented below:

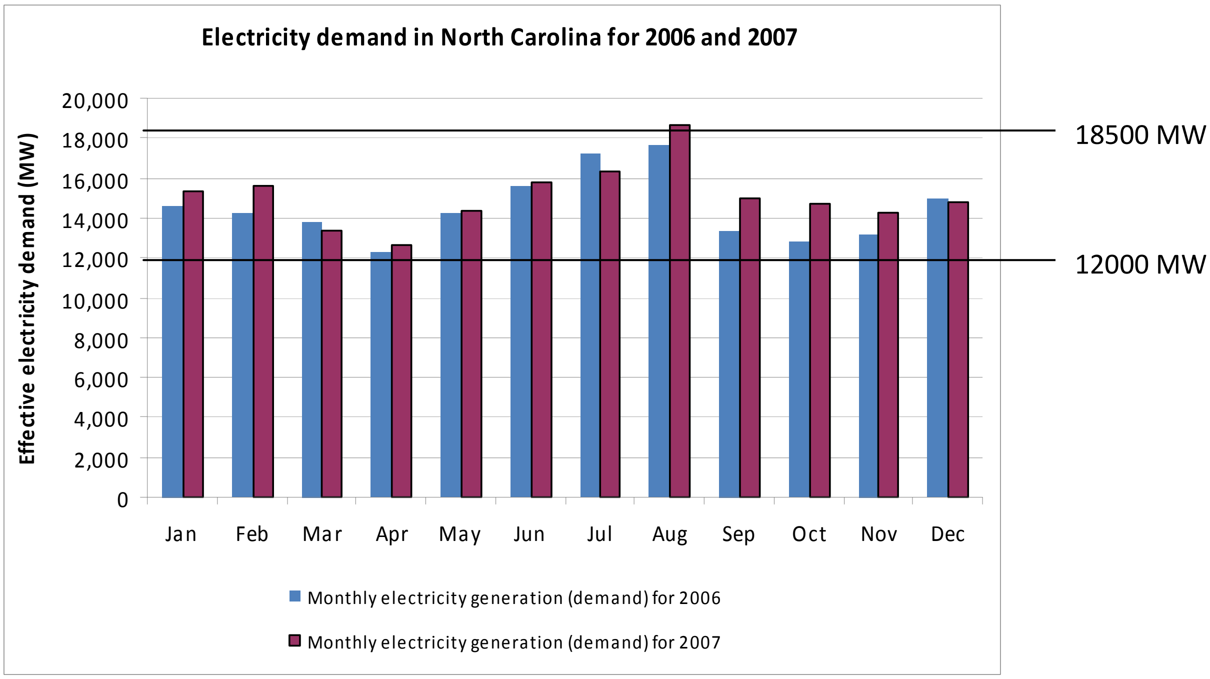


Figure 6: Month-by-month electricity consumed in North Carolina for 2006 and 2007[16]

From the consumption data, we may construct a demand curve by calculating the percentage of time in the year during which instantaneous electricity supplied is equal to or less than a certain level. Looking at the graph above for example, we see that for 100% of the time, North Carolina consumes electricity at a rate of 12 000 MW. Also discernable is that demand hardly ever rises above 18500 MW. The reality that there are brief periods where demand lies outside these bounds is hidden by the resolution of the data. Having data presented for monthly averages of electricity consumption, will only have an effect over the extreme ends of the demand curve. Over the mid-section of electricity demand curve, the (downward) slope of the curve will be affected to a much lesser extent. As a result, there will be no impact on the graphically determined average electricity demand level. The graph on the following page gives an indication of the curve shapes one may expect:

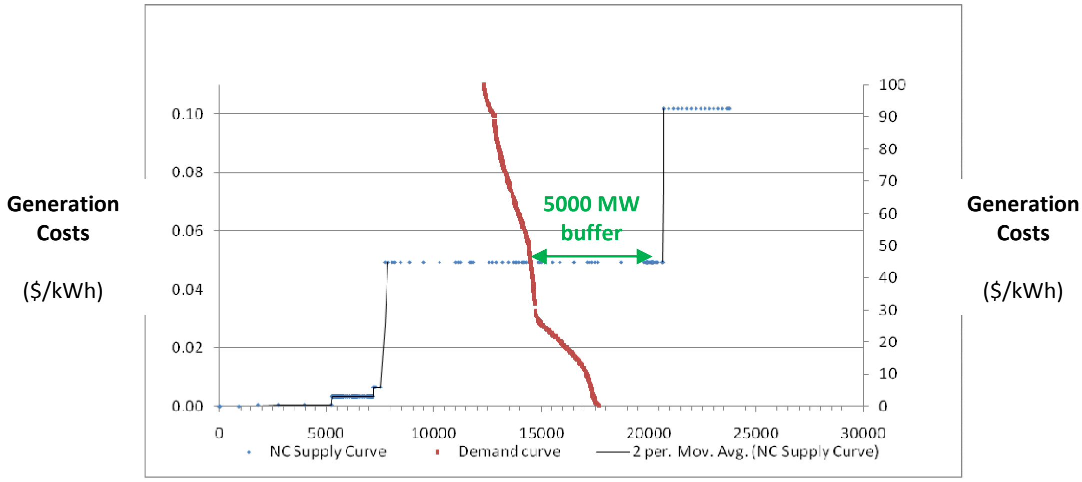


Figure 7: Example of a typical electricity sector supply and demand curves

The positions of the demand and supply curves relative to each other gives a rough indication of the average electricity consumption levels, along with the average electricity price level at the margin. As different power plants are brought offline due to water-constrained cooling duty, the width of the coal and nuclear plateaus on the graph above become shorter. This continues until a critical level is reached where the marginal (or intersection) price begins to increase sharply.

In the graph above, we see a buffer of roughly 5000 MW between average consumption levels and the limits of base load capacity. Despite this buffer, the profitability of utility companies during droughts will come under pressure earlier than this buffer suggests. This is because an steadily increasing proportion of electricity must now be supplied by peaking plants in periods of heightened demand. This loss in profitability may be quantified and used as a basis for expected economic loss from the point of view of the utility company. Such losses often become a basis for appeals to regulatory entities for an upward revision in tariffs. Alternatively, the losses may be used as a basis for investing in water or electricity-saving measures.

3. ANALYSIS – 1 (Physical indicators for potential or imminent plant showdown)

3.1 Lake Norman

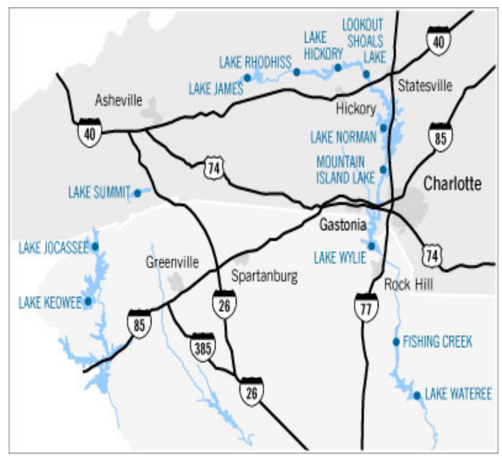
This water body is managed by The Duke Energy Corporation under the Catawba-Waterlee Comprehensive Relicensing Agreement (CRA). Under this contract, the lake level is to be kept between 93 and 100 feet – Duke targets 96 feet for most of the year. The monthly requirement schedule is shown in Table 2 below. Should the level fall below 93 feet in any month, power plants drawing water from this lake will have to be shut down. The adjacent map shows all the hydrological units upstream of Lake Norman where measurements can be made to forewarn the fall of water levels in Lake Norman.

Table 2: Lake Norman Level management requirements[17]

Lake Norman Elevations
(in feet on the 1st of the month)

Month(s)	Existing Guide Curve	Minimum	Target	Maximum
Jan	96	93	96	100
Feb	94	91	94	100
Mar	92	92.26	95.26	100
Apr	94	93.65	96.65	100
May	96	95	98	100
Jun – Sep	98	95	98	100
Oct	97.67	95	98	100
Nov	97.33	93.98	96	100
Dec	97	93	96	100
Dec 31	96	93	96	100

Map 1: Lake Norman and upstream hydrological units



Out of all the hydrological units (i.e. rivers and man-made dams) in Map 1, only the level of Lake James exhibits a meaningful correlation with Lake Norman (see graph below). As a small feed reservoir for the Catawba River, Lake James would act as a suitable indicator of imminent problems at Lake Norman.

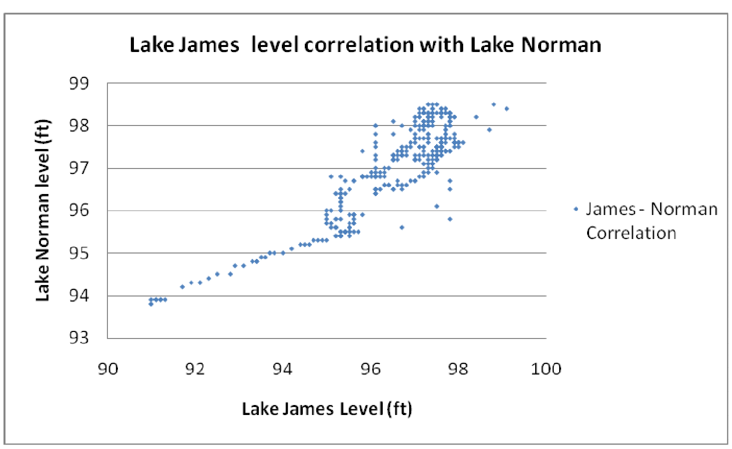


Figure 8: Correlation between levels in Lake James and Lake Norman

Water volumes at the artificial lakes between Lake James and Lake Norman (i.e. Lakes Hickory and Rhodhiss) may be released periodically on occasions where Lake Norman drops. This ensures that Lake Norman maintains the levels required to keep thermal power plants online which rely on its water. The distinctive correlation in Figure 8 shows however, that **when Lake James falls and stays below 89 feet, then generation plants at Lake Norman are under increased risk**. This relationship is confirmed by time-series data on the two lake levels for the past 13 months, as shown in Figures 9 directly below. The two profiles are quite similar, hence showing that the result in Figure 8 is to be expected.

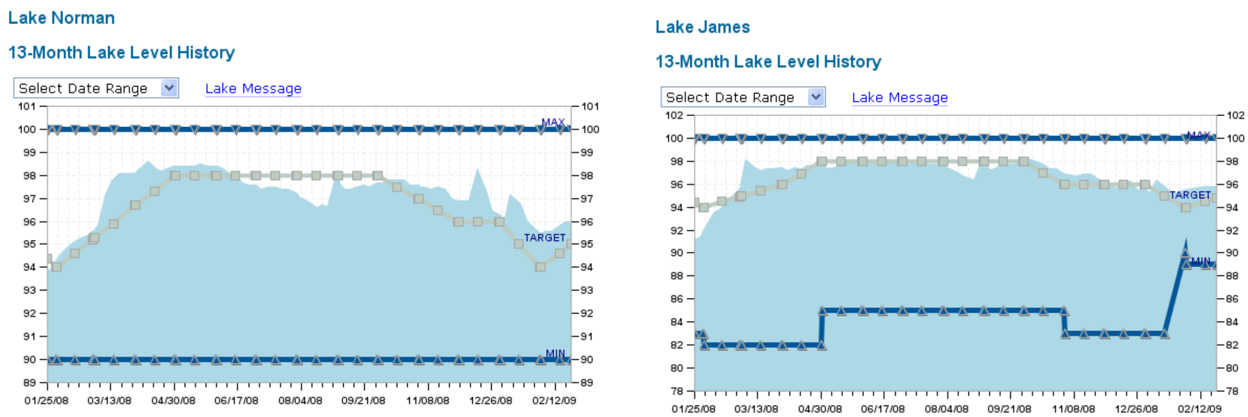


Figure 9: Comparison of time series data between Lake Norman and Lake James[18]

3.2 Lake Wylie

The graph below shows that Lake James may also be used as a proxy indicator for falling levels in Lake Wylie. This outcome is expected given that Lake Wylie is almost immediately downstream of Lake Norman. Table 3 on the right shows that the water levels in Lake Wylie are managed in much the same manner as those in Lake Norman. For Lake Wylie, the minimum water level for electricity generation is 94 feet. This constraint affects only the GG Allen coal power plant with capacity of 1155 MW.

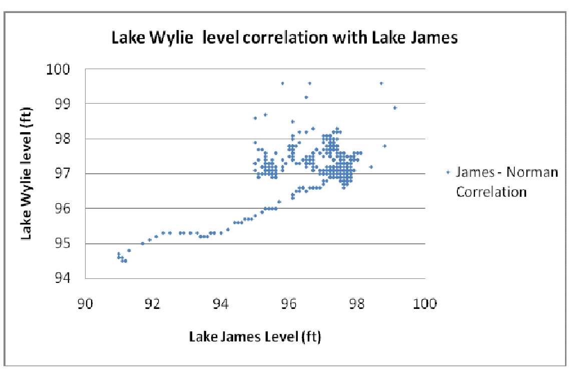


Figure 10: Correlation between Lake James and Lake Wylie

Table 3: Lake Wylie Level management requirements[17]

Lake Wylie Elevations
(in feet on the 1st of the month)

Month(s)	Existing Guide Curve	Minimum	Target	Maximum
Jan - Dec 31	97	94	97	100

From Figure 10 and 11, we see that at water levels of less than 90 feet in Lake James, operations for power plants at Lake Wylie are jeopardized. As was the case with Lake Norman, we see a relatively clear correlation between falling levels at Lake James and Lake Wylie using time-series data.

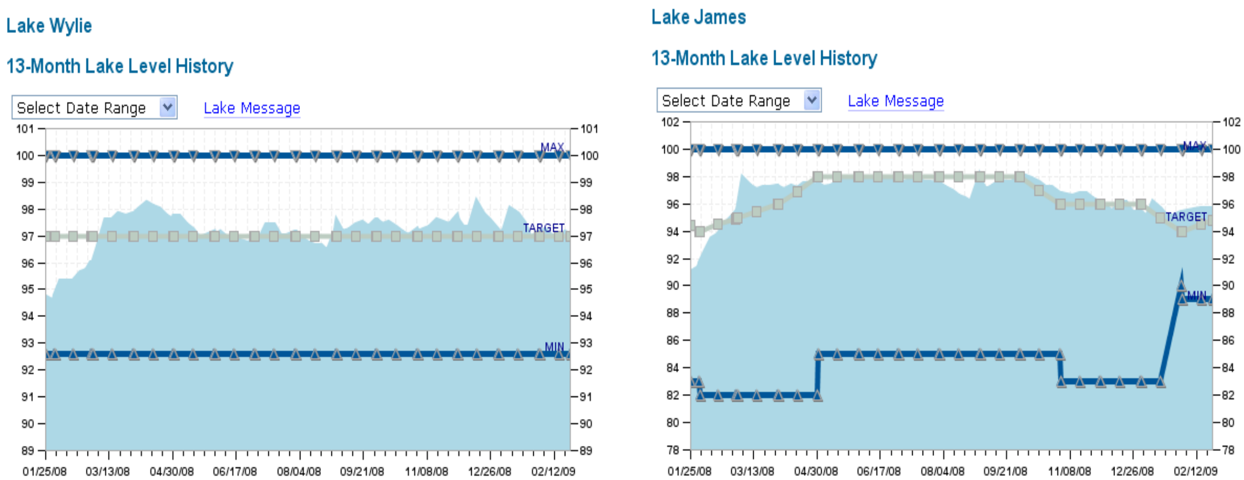


Figure 11: Comparison of time series data between Lake Wylie and Lake James[18]

3.3 Belews Lake

No direct measurement of levels at Belews Lake could be found from The Duke Energy Corporation series of lake management publications, or from state/federal lake monitoring agencies. In light of this, a slightly different approach is used to find an indicator for implementing drought countervailing measures. Surveys conclude that the water withdrawal ratio at the Duke Energy Corporation Belews Creek Coal-fired power plant is in the region of 30-40 gal/kWh.[19] With an electricity generation capacity of about 2240 MW, this implies roughly 54 000 000 kWh/day of electricity produced. A simple multiplication and minor adjustment to ensure consistency of units shows that each day a total of 2 150 million gallons of water is withdrawn from Belews Lake. Much of this water however is returned to the lake at a higher temperature.

The warm water plume from the generation plant discharge causes evaporation losses from the lake in the region of 300-400 gal/MWh.[7] This means that a grand total of about 21.5 million gallons of water is lost each day from the lake. As a consequence, Belews Creek, which feeds this lake, must replace water at a rate of at least **35-40 ft^3 per second**. Any sustained flowrate decrease substantially below this level – with the Belews Creek power plant operating at full capacity – would imply an imminent fall in the lake level.

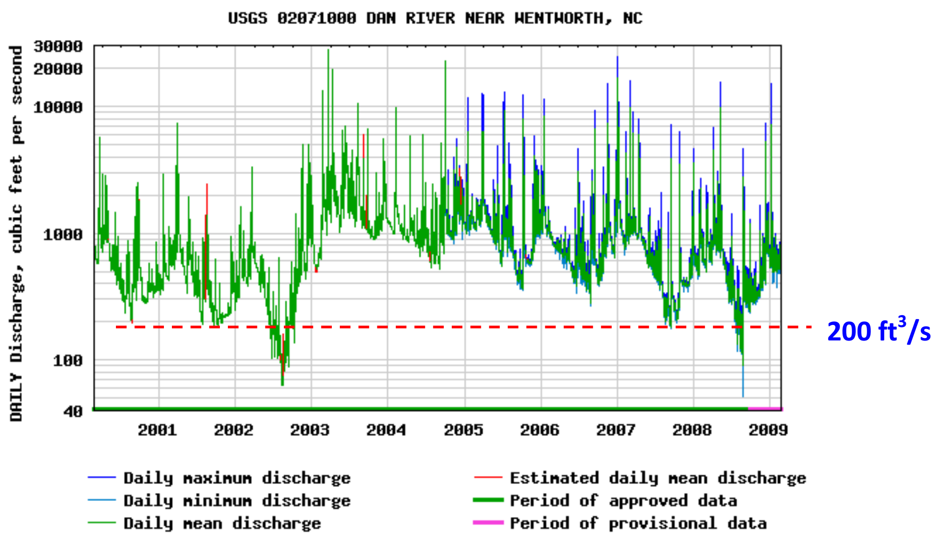


Figure 12: Historical record of volumetric flow rate in the Dan River which runs close to Belews Lake[20]

Figure 12 above, shows that a flow rate of below 40ft^3/s is almost never reached in the Dan River. The Dan River and Belews Creek (which feeds the lake) are not connected hence the graph above does not represent a water flow which feeds Belews Lake directly. Because Belews Creek is a smaller stream, there have been numerous instances when Belews Lake has suffered drops in water level. The Duke Energy Corporation, which manages the Belews Lake level, has ample capacity to pump water from the Dan River (represented in Figure 12) over into Belews Lake. Over the longer term, Duke Energy is pursuing construction and approval of a permanent intake and pump station to withdraw water from the Dan River and pump it into Belews Lake.[21] Figure 12 above shows that even in the protracted drought of 2007/2008, Belews Lake (with the help of water transfers from the Dan River which rarely flows at less than 200 ft^3/s) will remain one of the lakes in North Carolina that is able to continuously provide sufficient cooling water for electricity generation purposes.

3.4 Lake Harris

During the 2008 North Carolina drought, water levels at Lake Harris came within two feet of the minimum required for operations at the Shearon Harris Nuclear power plant. If the water level had reached 214 feet, electricity generation would have to cease while the plant management determined the best alternative means to cover the supply shortfall.[22] No data could be found on water levels at Lake Harris dating back over the period of the last drought. Despite this, it is possible to approximate the rate at which the water level would have dropped by observing the rate of water level depletion at neighboring lakes. Quantitative models estimating evaporation from lakes show that the most important determinants of the rate of water loss are: air temperatures, wind speeds, surface water temperature, air humidity, solar insolation and the temperature gradient of the water in the lake as a function of lake depth.[23]

The determinants mentioned above imply that only lakes in the immediate vicinity of Lake Harris may be used to approximate the rate of evaporation. One such water body is the B.Everett Jordan Lake situated within 5 kilometers northwards of Lake Harris as shown in the map below.

Figure 13: Map showing proximity of Lake Jordan to Lake Harris

These 2 lakes are not connected hence no water transfers occur between them for management of lake levels. Lake Jordan has readily available time-series depth data and in the graph below the rate of water level decrease is used as a proxy for what will occur at Harris Lake.

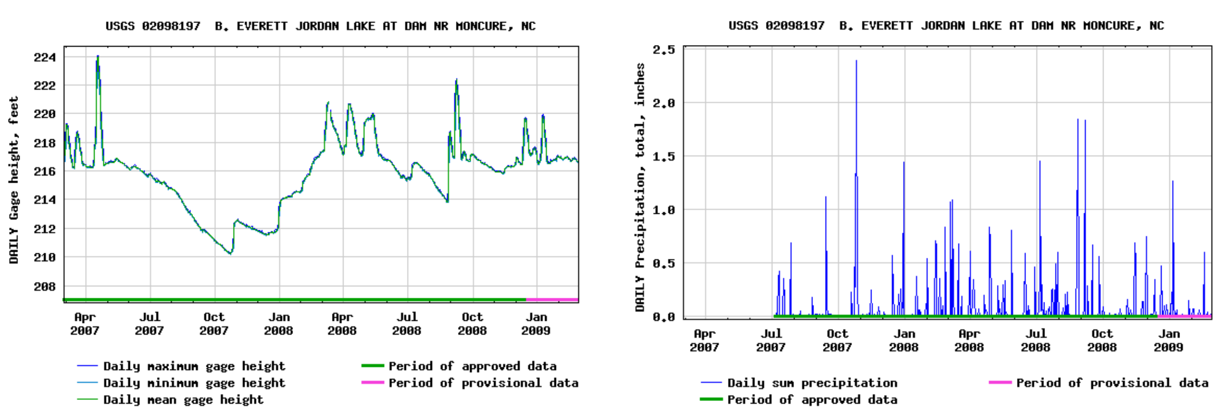


Figure 14: B.Everett Jordan Lake historic levels and precipitation in immediate vicinity[24]

The graphs in figure 14 illustrate that in periods of very low precipitation such as from July 2007 to October 2007, the **lake level will drop at a rate of approximately 1.2 feet every month**. It is also important to note that Harris Lake – with its surface area of about 17 km^2 and average depth of 18 feet – is less than half the size of Jordan Lake while also being much shallower. As a result, it will probably evaporate at a much higher rate. In addition to this, cooling water from the Shearon Harris Nuclear Power Plant is discharged at temperatures much higher than those observed at Lake Jordan. Given that Harris Lake water levels reached within 2 feet of the minimum levels allowed for cooling water intake at the Shearon Harris Nuclear Plant[22], only four to eight more weeks of continued drought would have led to a shut down of this power plant.

3.5 Lake Hyco

The largest coal plant operated by Progress Energy uses water from the Hyco Lake for cooling purposes. Three tributaries enter the main lake area from the southwest. The Roxboro coal plant lies towards the northern end of the lake and has an electricity generation capacity of over 2500MW. At this point, the three tributaries merge to form the Hyco River (see map below).

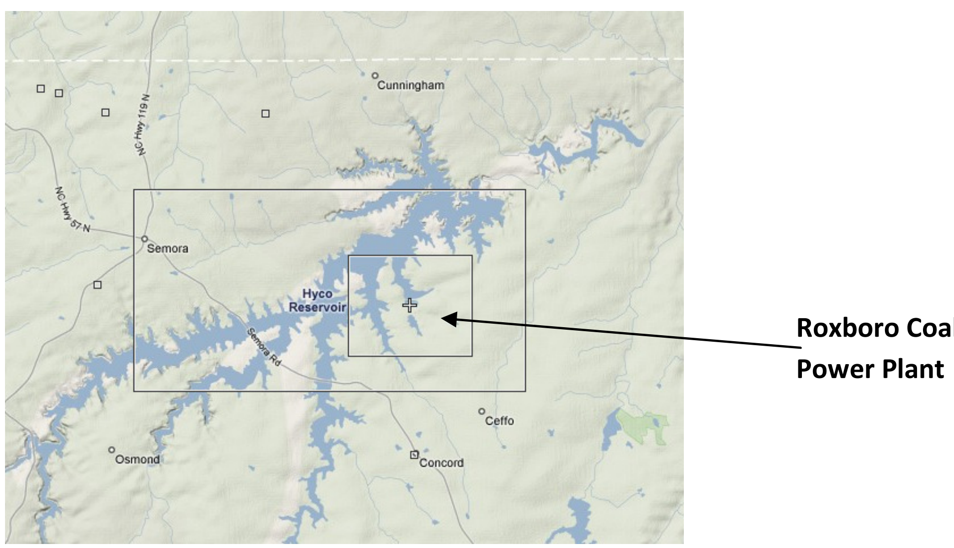


Figure 15: Position of Roxboro Coal Power Plant at Lake Hyco[25]

The United States Geological Survey (USGS) ceased recording flowrate data for the Hyco River, Cobbs Creek, North Hyco and South Hyco Creeks over a decade ago hence no relationships between lake level and flow may be established with the available data. As an alternative, we may only ascertain the rate of water level decrease as was done in the case of Lake Harris. The graph overleaf shows typical trajectories for water level drops.

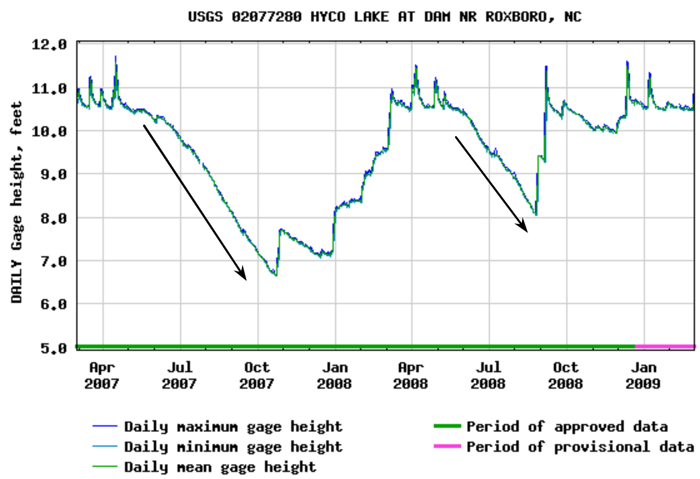


Figure 16: Time-series data for Hyco Lake water level over last 2 years

The droughts of 2007 and 2008 are clearly discernable from the graph above (and are indicated by the downward sloping arrows). In 2007, from the beginning of July to October, in the absence of precipitation, **levels drop** a total of 3 inches for an **approximate average of 1 foot per month**. This metric gives a rough indication of how much time operations at Roxboro plant may continue before having to cut back due to water constraints.

3.6 Lake Mayo

Along with the Roxboro Power Plant, the Mayo Coal Plant ranks among the larger coal-fired power plants in the Progress Energy fleet – built in 1983. To provide the cooling water, Mayo Creek was impounded to create Lake Mayo. Flow measurements are conducted along this creek by Progress Energy and may be used to correlate against the Mayo Lake level.

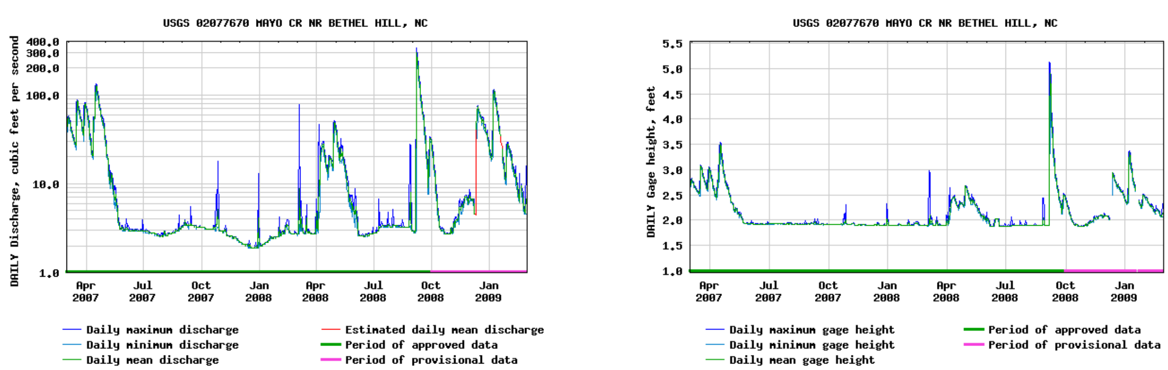


Figure 17: Time-series data for flow and gauge level on Mayo Creek over last 2 years

No data on Lake Mayo water levels could be found in the United States Geological Survey database. In the absence of specific lake level data, one may use an estimate water consumption of between 300-500 gallons per megawatt-hour; typical for a coal-fired power plant.[7] Using the last published capacity factor data from 2007, one establishes that the Mayo coal-fired power plant runs at an average generation rate of 480 MW (out of its nameplate 740 MW). The effective generation capacity coupled with the quoted energy-specific water consumption rate imply an average absolute water consumption rate of just under 6 million gallons a day (or approx. 9 ft^3/s). Figure 17 shows that this flow-rate is typically only sustained for less than 6 months every year. The map below shows however, that the flow measured at Bethel Hill (represented in figure 17) is not the main tributary into the Mayo Reservoir/Lake. The river feeding this water body runs from South to North while the measurement at Bethel Hill occurs in an off-stream flowing west of the Mayo reservoir and hence may not capture the full flow of the main tributary responsible for maintaining the level in the Mayo Reservoir.

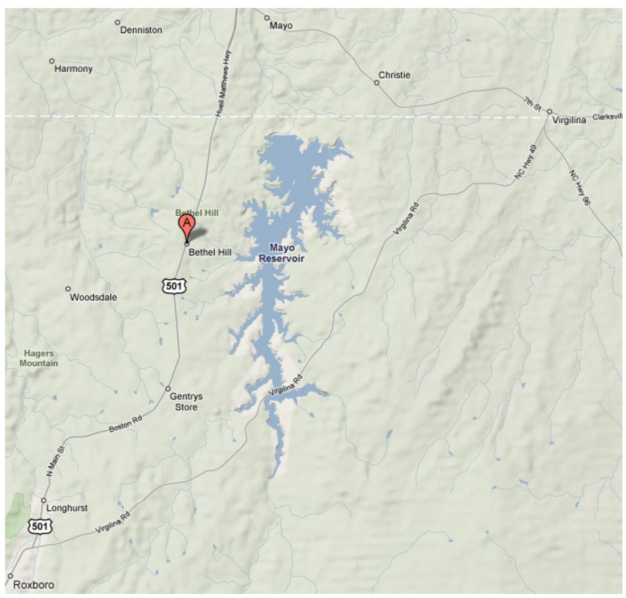


Figure 18: Aerial view of Mayo Reservoir

3.7 Lakes Sutton, Julian and Quaker Neck

No historical data was available on water levels or volumetric flows into or from these lakes. Fortunately, the coal power plants relying on these waters for cooling duty constitute a combined nameplate capacity of less than 1500 MW. The lakes examined in this section of the report, cover over 90% of the major base load and intermediate power plants across the state.

4. ANALYSIS – 2 (Finding the probabilities of drought in climatic regions within North Carolina)

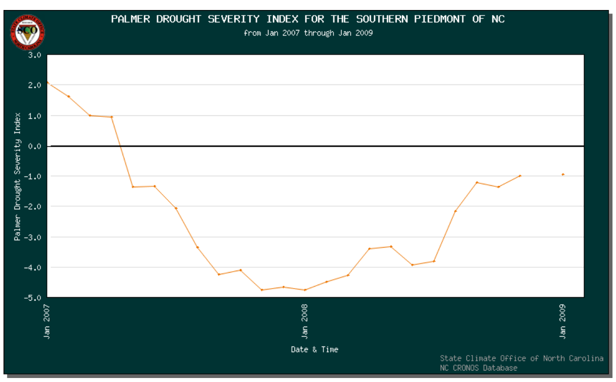
4.1 Lake Norman and Catawba River Basin

During the last North Carolina drought, the following generation plants (situated in the Catawba River Basin) were simultaneously brought under threat of shutdown.

McGuire Nuclear	2200 MW
Marshall Coal	1995 MW
Riverbend Coal	460 MW
Cowans Ford Hydro	350 MW

Combined capacity ≈ 5000 MW

Critically low water levels (i.e. below 92 feet) at Lake Norman, by extension, imply low flow and water levels along the Catawba River (see Map 1). Such levels are typically reached once the Palmer Drought Index drops to a value of negative 4 as was the case in January and February of 2008 (see graphs below).



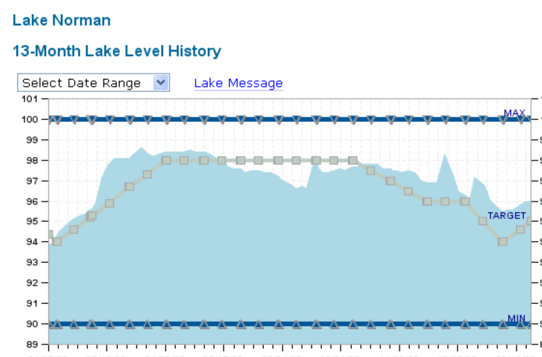
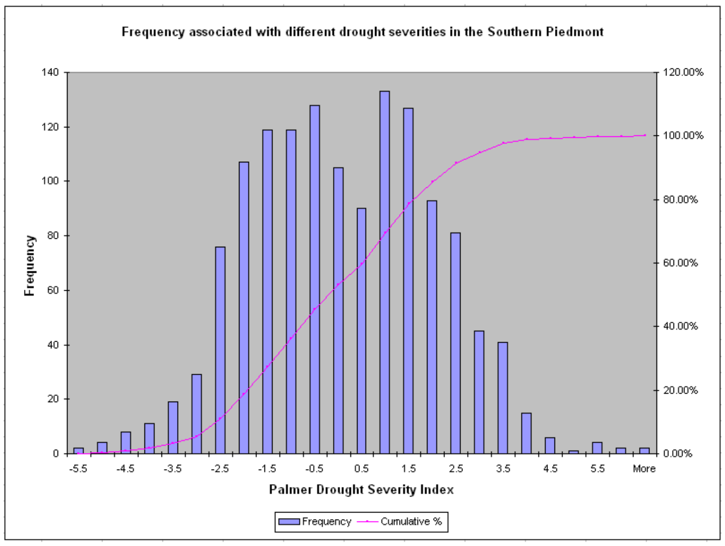


Figure 19: Illustration that critical level at Lake Norman are reached during -3 drought severity

In light of this, -4 on the Palmer Drought Severity Index level also marks the juncture at which electricity production in the 4 power plants listed above stops and is re-consigned to higher-cost natural gas power plants. Alternatively, extra electricity must be wheeled in from outside of the state. Having identified this threshold drought severity level, the objective now becomes estimating the frequency of this level of drought into the future. In the introduction to this report, it was noted that no academic (peer reviewed) papers could be found which identified a significant driver for the dry periods experienced in North Carolina. As a result, it is extremely difficult to make forward predictions. Alternatively, one may look at historical data and statistically characterize climatic trends seen in the Lake Norman/Catawaba

River region. The Palmer Drought Index Data for North Carolina has been recorded since 1895, hence there is an adequate data set from which to evaluate the probability of drought occurring in the region.

The graph below displays a histogram showing the frequencies with which given drought severities have occurred over the last century. Also shown are the summary statistical data which allow one to generate random drought scenarios which adhere to the statistical parameters.



Bin range	Frequency	Cumulative %
-5.5	2	0.15%
-5.0	4	0.44%
-4.5	8	1.02%
-4.0	11	1.83%
-3.5	19	3.22%
-3.0	29	5.34%
-2.5	76	10.90%
-2.0	107	18.73%
-1.5	119	27.43%
-1.0	119	36.14%
-0.5	128	45.50%
0.0	105	53.18%
0.5	90	59.77%
1.0	133	69.50%
1.5	127	78.79%
2.0	93	85.59%
2.5	81	91.51%
3.0	45	94.81%
3.5	41	97.81%
4.0	15	98.90%
4.5	6	99.34%
5.0	1	99.41%
5.5	4	99.71%
6.0	2	99.85%
More	2	100.00%

Figure 20: Occurrence frequency of disparate drought severities over the area of the Catawba River Watershed.

Climatic conditions in North Carolina over the last century exhibit an average Palmer Drought Severity Index of -0.1358, with an accompanying 1.946 standard deviation on the Index. A simple calculation using the cumulative frequency curve shows that there is roughly a 1 in 30 chance that a drought with a severity at least -3.5 occurs. This is shown by the cumulative probability function exhibiting a value of 3.22% at a Palmer Drought Severity of -3.5 or less (see table in Figure 20). Expressed differently, this means that over a 30-year period, a drought of such severity will occur at least once.

4.2 Lake Wylie

As noted earlier, several other powers plant may be affected during droughts. The next generation plant examined is the GG Allen coal-fired power plant. The two graphs below show that even at a drought severity level of -4 to -5, there is still sufficient water in this lake to support operations at the power plant. Figure 20 shows that no drought of greater severity than -5 has occurred in over 100 years of drought monitoring. For investment or contigency planning then, one may assume that the supply of water at Wylie will be secure relative to other parts of North Carolina.

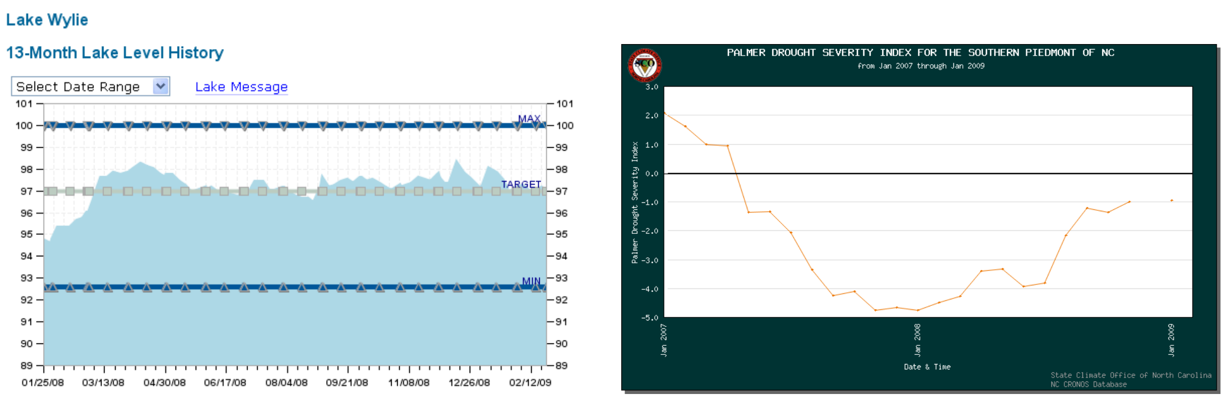


Figure 21: Illustration of stable water availability at Lake Wylie

4.3 Belews Lake and Dan River System

The Dan River is used by The Duke Energy Corporation to supplement water levels in the Belews Lake. Looking at the historical data, we see that flowrates in the Dan River have never dropped below the requisite 40 ft^3/s in the last 70 years (see left-hand graph on Figure 22). This flowrate level is able to maintain an adequate level in the Belews Lake for continuous operations at the Belews Creek Coal Fired Power Plant. In light of the very low probability of water shortages at this generation unit, cost implications will not be examined for this site.

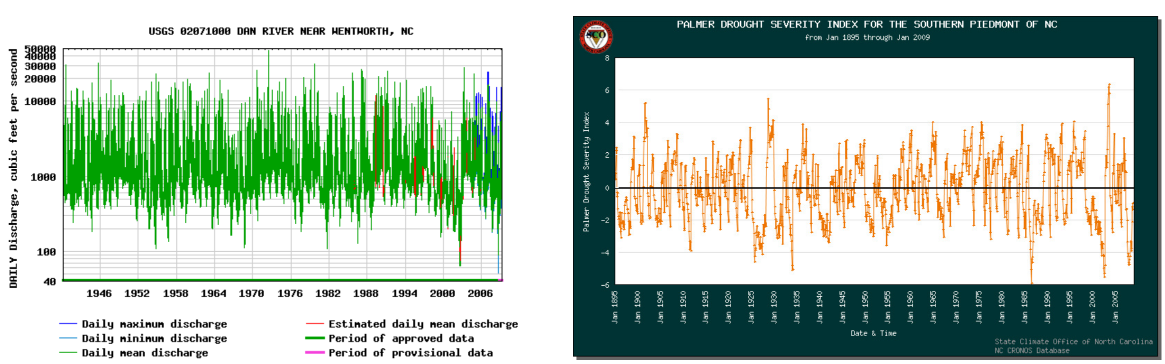


Figure 22: Dan River feeding Belews Lake maintains flowrate of at least 40ft^3/s at all drought severities over last 100 years

4.4 Harris Lake

For the Shearon Harris Plant, press releases from The Progress Energy Corporation state that operations at this plant were under imminent threat of closure if the 2007/2008 drought had persisted. The most acute water–related limitations occurred during January 2008 when lake levels were within 2 feet of the allowable minimum. The Shearon Harris Plant is situated in the southern portion of Wake County which makes up part of the Central Piedmont climatic region of North Carolina. Over this time the Palmer Drought Index profile was hovering around the -4 level and progressed as shown below:

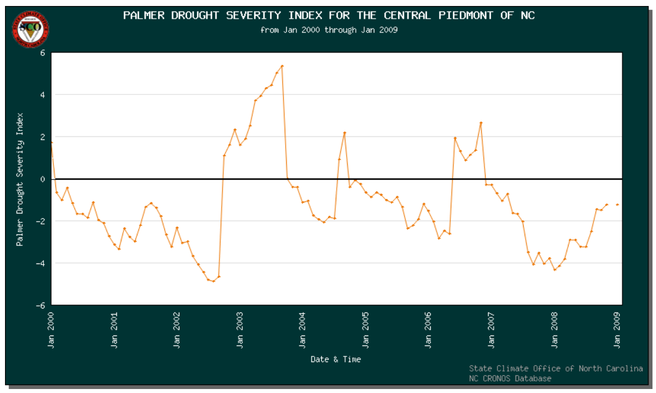
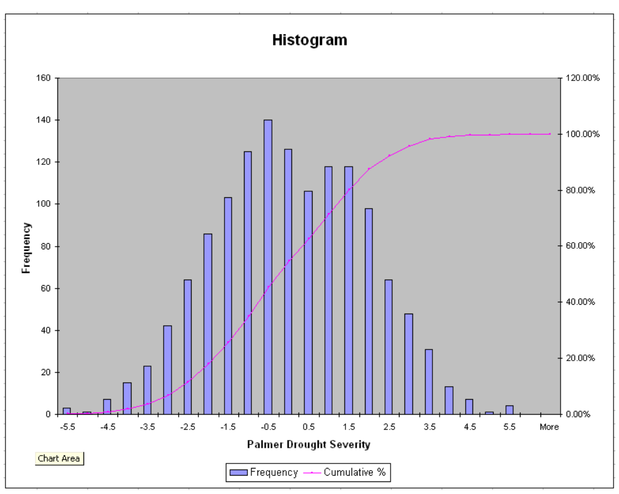


Figure 23: Palmer Drought Severity Index over Central Piedmont for the last decade

As before, historical data may be used to estimate the probability of drought occuring in this region with a severity greater than -3.5. According to the historical record for the Palmer Drought Severity Index, the Central Piedmont region of North Carolina is slightly more prone to drought (relative to the southern Piedmont Region) as the histogram and table below show:



Bin range	*Frequency*	*Cumulative %*
-5.5	3	0.22%
-5.0	1	0.30%
-4.5	7	0.82%
-4.0	15	1.94%
-3.5	23	3.65%
-3.0	42	6.78%
-2.5	64	11.54%
-2.0	86	17.94%
-1.5	103	25.61%
-1.0	125	34.92%
-0.5	140	45.35%
0.0	126	54.73%
0.5	106	62.62%
1.0	118	71.41%
1.5	118	80.19%
2.0	98	87.49%
2.5	64	92.26%
3.0	48	95.83%
3.5	31	98.14%
4.0	13	99.11%
4.5	7	99.63%
5.0	1	99.70%
5.5	4	100.00%
6.0	0	100.00%
More	0	100.00%

Figure 24: Occurrence frequency of disparate drought severities over the Central Piedmont Area.

The cumulatve frequency of all dry periods where drought severity surpasses -3.5 amounts to about 3.65% of all recordings. This implies – based on historical data – that over 100 years, the equivalent of 3.65 years were under condictions of drought severe enough to stop operations at Shearon Harris. The first instance occurred during the 2003/2004 drought. The latest drought in early 2008 though quite serious, did not reach -4 on the Palmer Drought Severity Index. Given that the last decade has seen 2 severe droughts in the Central Piedmont region, one cannot discount the possibility that this may be part of a more general trend to increasingly frequent severe droughts in this region. In light of this, the financial implications of a Shearon Harris shutdown will also be included in the cost calculations.

4.5 Lower Cape Fear River Basin

The Southern Coastal Plains region in North Carolina, where the Brunswick Nuclear Plant is situated, experiences drought frequently when compared to the Piedmont Regions. The Brunswick Plant is however, sited within a few kilometers of the southeastern North Carolina coast along a stretch of the Cape Fear river with consistent water flows into the Atlantic Ocean. As a result, there is a very low likelihood that this electricity generation facility will experience any water shortages. Even during the severe drought of late 2007/early 2008, no media reports could be found disclosing operational problems due to water scarcity at the Brunswick Power Plant. This facility will hence not be included in our cost calculations.

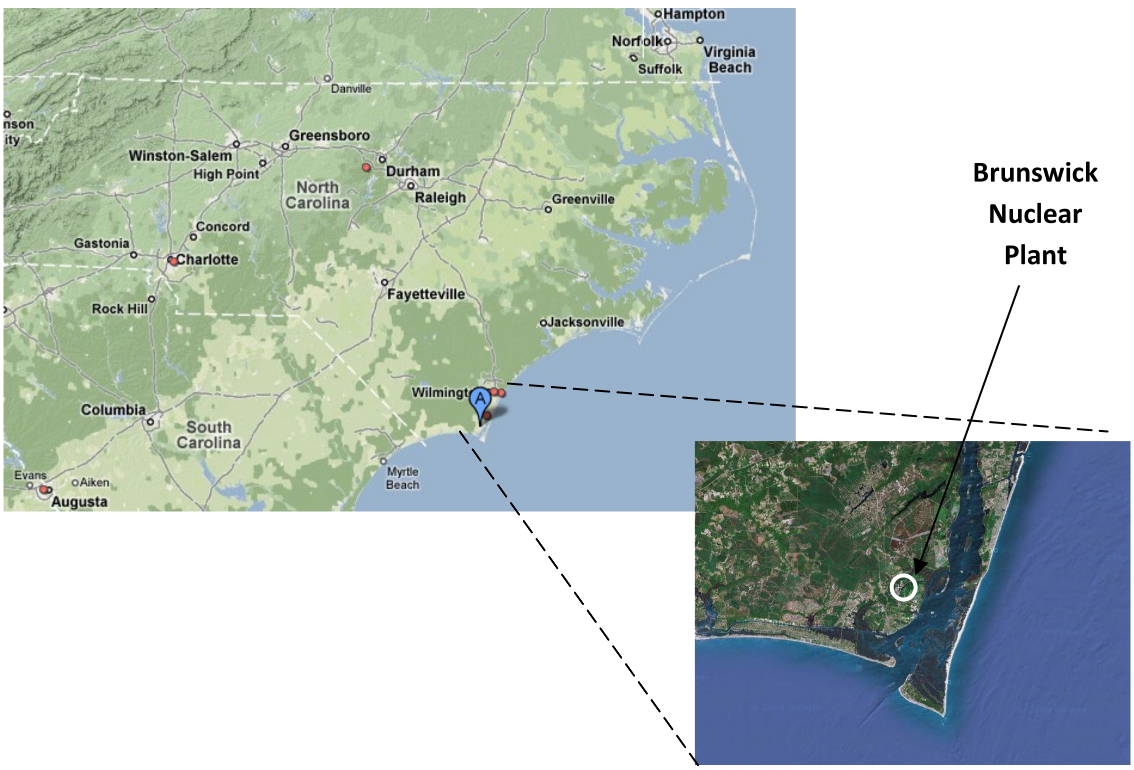


Figure 25: Position of the Brunswick Nuclear Power Plant operated by the Progress Energy Corporation.

4.6 Roanoke River Basin

The Roxboro Coal-fired power plant lies in the northern Piedmont region, where recordings of drought severity exceeding -3.5 are less than 3% of all recordings since 1895. A drought severity level of -3.5 is chosen in the cost-estimates for the Northern Piedmont Region because water levels in Lake Hyco start dropping at this stage as shown in Figure 26 below:

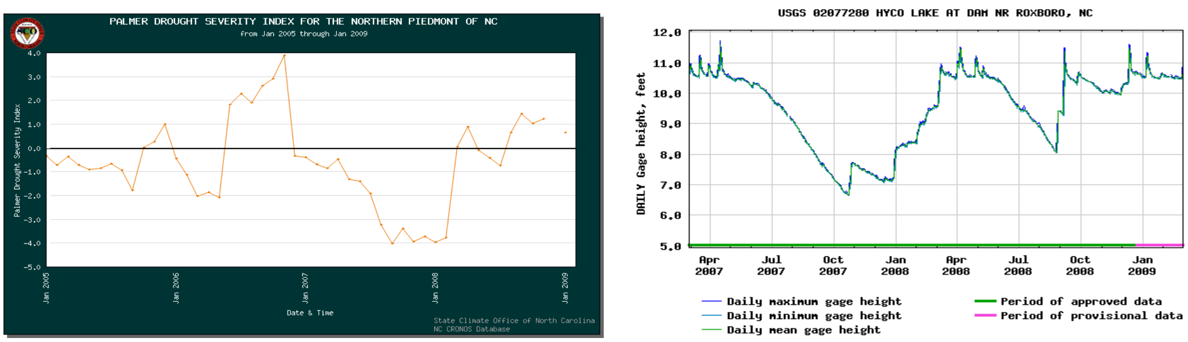
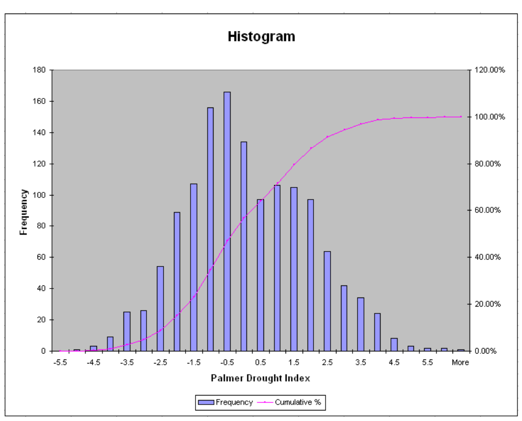


Figure 26: Correlation between Palmer Drought Index and water level Lake Hyco

Figure 26 illustrates that water levels in Lake Hyco started falling in July/August of 2007. The graph above showing the drought index for the Northern Piedmont Region, demonstrates that drought severity reached -4 at this time. Lake Mayo – being located within the northern Piedmont Region – has only been subjected to a drought severity of -3.5 or below for 2.8% of the time over the last 100 years. Shifting the histogram bin range to -4 or below on the Palmer Index shows a major drop in the probability down to 0.98% (See table in Figure 27). No press releases or warnings were issued on drought-related concerns for electricity generation units in this area during the droughts on record. Water supplies for power generation in this region can therefore be considered relatively stable.



Bin range	Frequency	Cumulative %
-5.5	0	0.00%
-5.0	1	0.07%
-4.5	3	0.30%
-4.0	9	0.96%
-3.5	25	2.80%
-3.0	26	4.72%
-2.5	54	8.71%
-2.0	89	15.28%
-1.5	107	23.17%
-1.0	156	34.69%
-0.5	166	46.94%
0.0	134	56.83%
0.5	97	63.99%
1.0	106	71.81%
1.5	105	79.56%
2.0	97	86.72%
2.5	64	91.44%
3.0	42	94.54%
3.5	34	97.05%
4.0	24	98.82%
4.5	8	99.41%
5.0	3	99.63%
5.5	2	99.78%
6.0	2	99.93%
More	1	100.00%

Figure 27: Histogram showing the frequencies associated with varying degrees of drought on the northern Piedmont Region

4.7 Summary of the results in Analysis Section 2

The following table summarizes the frequencies with which severe drought oocurs in each of the climate regions in North Carolina:

Table 4: Frequency of severe drought in each climatic region in North Carolina

Region within state	Total Palmer index counts since 1895	Palmer Index counts at or below -3.5	% counts below -3.5 Palmer Index
Southern Mountains	1368	41	2.997
Northern Mountains	1356	25	1.844
Northern Piedmont	1368	38	2.778
Central Piedmont	**1356**	**49**	**3.614**
Southern Piedmont	**1368**	**44**	**3.216**
North Coastal Plains	1368	32	2.339
Central Coastal Plains	1368	38	2.778
South Coastal Plains*	1356	57	4.167

*Only major power plant in this region is the Progress Eneryg Brunswick Nuclear Plant which is situation on the coast

The map below shows the locations of the regions listed in Table 4.

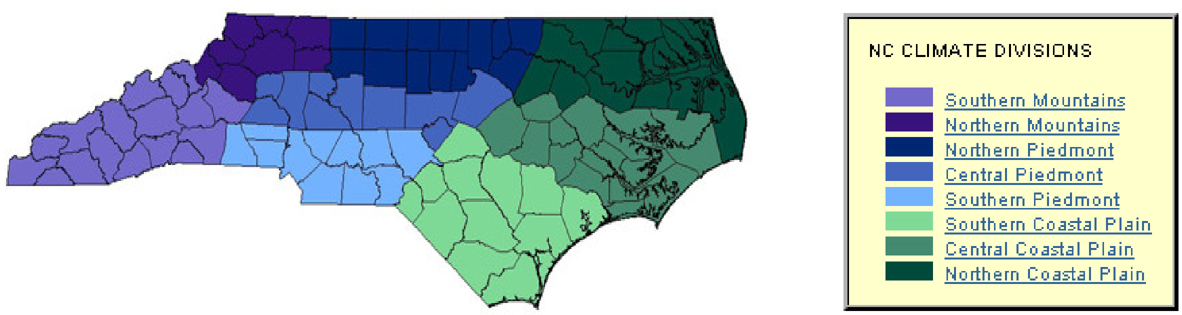


Figure 5: Division of North Carolina into climate regions for Palmer Drought Index measurements

There are only 2 regions in the state which have the combination of substantial electricity capacity and high propensity for drought conditions. These areas are marked in red print (see Table 4 above), namely the Central and South Piedmont Regions where the following major power plants are to be found:

McGuire Nuclear	2200 MW
Marshall Coal	1995 MW
Riverbend Coal	460 MW
Cowans Ford Hydro	350 MW
Shearon Harris Nuclear	900 MW

Combined ≈5900 MW of capacity

5. ANALYSIS – 3 (Quantifying losses in the event of severe drought)

Having identified the Central and Southern Piedmont Regions as areas of vulnerability, we may cover all possible loss incurring drought scenarios for power plants at Lake Norman, The Catawba River and Lake Harris over 30 years. A period of 30 years is chosen because of the frequency of drought observed over the monitored 100 year period. At just over 3% cumulative frequency, such droughts would occur roughly once every 25-30 years. Occurrence of drought in each individual year over a 30 year period will have a unique present value for financial losses assuming there is no additional capacity brought online. The present value will depend on the discount rate used, the drought-induced increase in generation costs, the point of view considered and the duration of the drought. Possible ranges for each of these parameters is discussed briefly here:

Discount rate:

The rate used to discount future cash flows to their present values is a key variable in quantifying the economic cost of drought-related impacts. Several approaches are used to choose a rate including:

- The **prescriptive approach**, which is usually associated with relatively low discount rates. Under a prescriptive approach, the social discount rate is estimated between 0.5% and 3%. Such low discount rates tend to magnify the adverse effects of climate-related events and are used by environmental agencies to justify investments in alternative technologies. Such rates are chosen based on ethical considerations so that we do not unjustly underestimate the negative impact of imprudent decision-making on future generations.

- The **descriptive approach** which focuses on the opportunity cost of capital, looking at investments made in the real world – setting the discount rate accordingly. Advocates for these relativly higher discount rates (i.e. 3% - 7%) argue that if the return on investment mitigating drought impacts lies below that exhibited by other investments, then it is better to deploy resources away from investment mitigating the environmental problem (in our case, the adverse impact of the drought). They also argue that discount rates are dsclosed by the actual choices of people rather than what prescriptive economists feel those choices should be. At present society generally spends relatively small amounts on drought mitigation measures and this trait is aligned with higher discount rates of future flows of cost and/or benefits.

Point of view:

Losses incurred during times of drought are related to higher generation costs associated with increased operations at natural gas plants or emergency imports of electricity. Where the electricity supply industry is privatized, these costs will be borne solely by the energy utility company whose operations are affected. In addition to this, passing on cost increases is not possible in the short term where utilities operate within price-regulated states. Valuation of these potential future losses will be conducted by the private utility company. The approach taken in our analysis will be to **examine both the losses sustained by the state economy and private utility companies** under varying discount rates such that a tool is developed which allows quick evaluation of the financial or economic implications of drought.

Commonly used discount rates:

The United States Office of Management and Budget, in Section 8.2 (b) of their updated Circular A-94 outlining "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs", employ a discount rate of 7% for public investments. The proviso for using this rate however, is that the investments concerned generate *constant-dollar* costs and benefits. The rationale backing this is that 7% mirrors the average marginal pretax rate of return on a private sector investment in recent years. Various federal economic oversight agencies such as The Congressional Budget Office (CBO) contend however, that the performance of investments should be measured against the yield on Treasury Debt – implying a real discounting rate closer to 2%. The Government Accounting Office (GAO) advocates for a slight variation on the CBO approach where the rate mirrors the yield on United States treasury debt with a maturity equal to the length of the project or policy action. According to the OMB, the 30-year interest rate on treasury notes and bonds is 3%.

In light of all the disparate views from differing government agencies, only the results using 0% and 7% discount rates will be examined to give a sense of the upper and lower bounds on the cost implications. The report will include demonstrated calculations so that one may redo the calculation with their own preferred discount rate to more accurately quantify costs associated with drought-related electricity supply disruptions.

5.1 Impact on margin of net income:

According to energy analysts at Dahlman Rose & Company, marginal electricity supply costs under severe drought conditions could increase by a factor of between five and ten.[26] Given this wide range of potential impact on supply side cost, the implications of the drought will be presented for a range of cost increases in the same manner as is done with the discount rate. This approach establishes an upper and lower bound on the supply costs spikes. In the methods section, we assumed 2c/kWh as the electricity production cost for nuclear power plants. In light of this, results may potentially be presented for production cost increases of up to 20c/kWh.

5.2 Timing of event:

The year in which severe drought occurs is also significant in quantifying the present value economic loss to privately-owned utility companies and the state. The importance relates to the time-dependent value of money. Incidents of drought occuring earlier have more profound impacts as financial losses are discounted to a lesser degree.

The last dimension of the scenario analysis will examine the economic impact of severe drought in each of the 20-30 years onward from the present. This will be done only for regions of the state where the probability of a severe drought occuring is greater than 3% (i.e. at least once every 30 years). With 30 individual years in which the drought may occur, 7 different discount rates to examine and multiple price increases to simulate, the permutations on impacts are too numerous to be presented succinctly graphically here.

The results presented therefore, will depict two important cases as well as the extreme upper and lower bounds on the present value costs incurred. In the first scenario, we assume that stoppage of nuclear and coal plants will be covered completely by generation from less water-intensive natural gas plants. In such a case, generation costs would increase from the 2-3c/kWh range up to roughly 8-9c/kWh (for a cost increase of 6c/kWh). This *excludes the effect of increased natural gas prices* due to higher reliance on gas-powered peaking plants.

5.3 Incurred cost due to switching to natural gas (ascribed to difference in generation cost)

When switching generation from a combination of coal and nuclear plants over to natural gas, normalized per kilowatt-hour costs rise from 2-4 c/kWh up to approximately 8-9c/kWh.[15] This implies a cost rise of 6 c/kWh. To determine the total cost for the switch, a few assumptions must be made about the duration of the electricity supply disruption both on a daily and seasonal basis. The assumptions used in our calculations are as follows:

- Shutdown of any power plants mentioned and the **6c/kWh cost increase (associated with closure or shutdown of those plants) is sustained for only 3 months out of the entire year in which the severe drought occurs**. The premise here is that electricity demand will peak during this time and evaporation rates from fresh surface water sources will accelerate during this warm summer season, placing additional strain on fresh water sources.
- In addition, it is assumed that the peaking or intermdiate natural gas plants are only operated for an extra 6 hours of the day (during the morning and afternoon when electricity demand is highest)

Example calculation: All 5900 MW of capacity brought offline due to water shortage

5900 x 365 x 24 x (3/12) x (6/24) x (0.06) x 1 = $193 815 000

0 discount rate, 3 months per year, 6 hours each day, drought in year 0

Price increase of 6c/kWh (shortfall covered by natural gas plants)

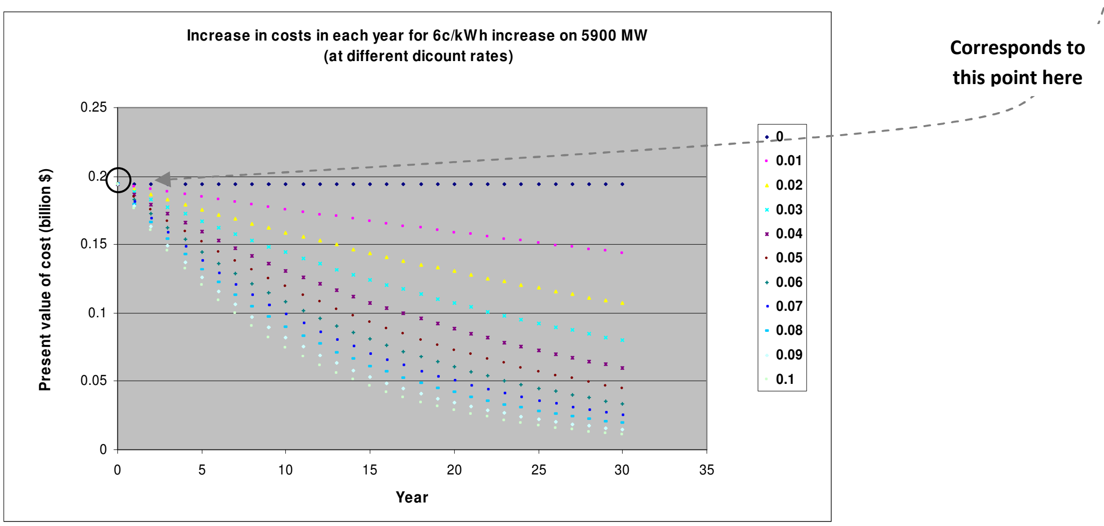


Figure 28: Range of present value drought-related financial losses in the Catawba River Basin System if shortfalls covered by natural gas plants

Under such a scenario, aggragate present value costs incurred by power plants using water from the Lake Norman and Catawba River system will range from \$25 million to \$195 million.

Price increase of 8-10c/kWh (shortfall covered by electricity imports)

A second important scenario sees utility operators of these 5 power plants having to wheel-in emergency electricity from neighbouring states. Four of the power plants under consideration are operated by The Duke Energy Carolinas Corporation which only has operations in North and South Carolina. The fifth generator (Shearon Harris) belongs to and is operated by The Progress Energy Corporation – a company which also, for the most part, has generation capacity in the Carolinas. Failing excess capacity in South Carolina, electricity will have to be sourced primarily from Virginia or Tennessee. In addition, supply shortages in electricity will most likely occur during daytime periods of peak demand – implying that the *highest retail tariffs* will be paid to cover the shortfall – tarriffs that will typically be 8-10c/kWh above the generation costs associated with nuclear and coal power plants.

Example calculation: All 5900 MW of capacity brought offline due to water shortage

$5900 \times 365 \times 24 \times (3/12) \times (6/24) \times (0.1) \times (1/1.03^{16})$ = \$ 201 298 500

3% discount rate, 3 months per year, 6 hours each day, drought in year 16

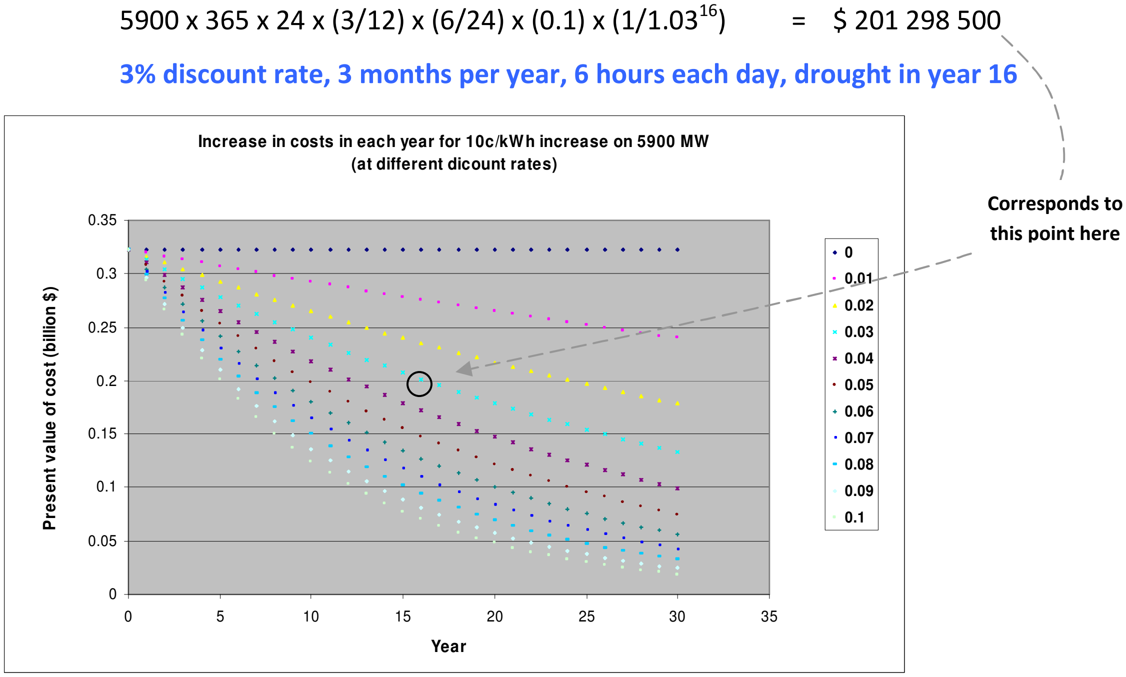


Figure 29: Range of present value drought-related financial losses in the Catawba River Basin System if shortfalls cover by electricity imports

Under such a scenario, with discount rates ranging from 0% to 7%, aggragate costs incurred by power plants using water from this river system will range from \$50 million to \$320 million.

5.4 Finding the effect on natural gas prices(when entire shortfall is covered by NG plants)

Within the Central and Southern Piedmont Regions, the following power generation plants are most likely to frequently be subjected to severe drought conditions. Also shown in the table below are the respective amounts of natural gas that would be required to fuel extra peaking units to make up for the production shortfall in the drought-affected areas.

Table 5: Illustration of the natural gas that will be used to fuel combined cycle power plants that will cover baseload shortfall.

Region	Power Plant	Capacity	Fuel used to cover production shortfall*
			Natural gas (MMcf)
Southern Piedmont	McGuire Nuclear	2200 MW	16716.3
Southern Piedmont	Marshall Coal	1995 MW	15158.7
Southern Piedmont	Riverbend Coal	460 MW	3495.2
Southern Piedmont	Cowans Ford Hydro	350 MW	2659.4
Central Piedmont	Shearon Harris	900 MW	6838.5
			TOTAL 44868.1

*based on operation for 3 months out of the year and 8 hours of peak electricity demand each day

According to the International Geothermal Association, a natural gas power plant (using combined cycle technology at 60% efficiency) consumes fuel at a rate of 315 g/kWh or 0.6945 lb/kWh.[27] At a typical density for natural gas of 0.05 lb/ft^3 (at standard temperature and pressure), this is the equivalent of 13.89 ft^3/kWh. The figures entered into the final column of Table 5 assume that the combined cycle plants will be used to cover the shortfall only for periods of heightened electricity demand (i.e. 3 summer months for 6 out of 24 hours of the day). With this set of assumptions, the total amount of natural gas used to cover outages at the power plants listed in Table 5 is determined as follows:

Total nameplate capacity: 2200 + 1995 + 460 + 350 + 900 = 5900MW (5900000 kW)

Shortfall kWh: 5900 000 x (3/12) x (6/24) x 365 x 24 = 3230246769.75 kWh

Natural gas used: 3230246769.75 kWh x 13.89 ft^3.kWh^{-1} = 44,868.13 million ft^3

So, we have approximately 45 000 million ft^3 of extra natural gas demand occurring over a 3 month stretch of the year. Examining data from the Energy Information Agency, we note that over the summer months (June, July and August) consumption of natural gas for the entire country is 5,022 billion ft^3,[28] while demand from all consumers within North Carolina was at roughly 48,921 million ft^3 over the same

3 months in 2008.[29] This shows that operations stoppages at the power plants listed in Table 5 have the potential to increase in-state demand for natural gas during this time by just over 90% (44,868 million ft^3 ÷ 48,921 million ft^3 = 0.917) under the assumptions previously stated (i.e. natural gas plants runs an extra 6 hours a day, for 3 months of the year). Compared to national consumption of natural gas however, an extra 44,921 million ft^3 represents an increase of only 0.894%. In relation to national consumption, less than 1% may seem negligible but it is important to remember that a severe drought will most likely affect the bulk of the Southeastern region of The United states as opposed to North Carolina in isolation. After extrapolating forecasted natural gas demand to include other states of the Southeast, the change in demand for natural gas at the national level could be as high as 5-10%.* The National Energy Modeling System (NEMS) used by The United States Department of Energy uses short-term price elasticities ranging from -0.24 to -0.28.[30] Using these NEMS estimates together with the defining equation for price elasticity written below, it is implied that a demand increase of 1% yields a price increase of 3% to 4%.

*Southeastern states would include: South Carolina, North Carolina, Georgia, Mississippi, Tennessee, Alabama

Price Elasticity of Demand

$$E_d = \frac{\%\ \text{change in quantity demanded}}{\%\ \text{change in price}} = \frac{\Delta Q_d / Q_d}{\Delta P_d / P_d}$$

With a price elasticity of -0.25 for example, the prospect of ramping up natural gas imports to cover shortfalls in baseload electricity generation is extremely expensive with a rough estimate indicating that national natural gas prices would increase by anywhere between 20 and 40% (i.e. 5-10% as noted in the previous paragraph, an then divided by the elasticity 0.25). An extra 44,900 million ft^3 of imported natural gas even at the normal 2008 summer peak price of $12 per 1000 cubic feet[31] amounts to an expenditure of over US$ 538.25 million through the duration of the summer peak demand season. A natural gas price increase of 20% to 40% would mean prices closer to US$16 per 1000 ft^3 and this does not include the effect of potential regional supply constraints due to limited pipeline transport capacity. Such added bottlenecks could potentially increase natural gas prices well over 50%. If prices were to rise (by 20% or 40%) to US$14.4 or US$16.8 per 1000 ft^3, an extra expenditure of US$ 646 million or US$ 754 million respectively, would be needed to provide adequate natural gas.

To put these expenditures in persective, in February 2009, the 10-K financial report submitted to the Securities Exchange Commission (SEC) by The Duke Energy Corporation disclosed a net income of $1.362 billion.[32] A complete shut of major power plants in the Catawba River Basin system under the assumptions noted here (and subsequent attempt to make up the shortfall with natural gas powered electricity) has the potential to offset over half the company-wide profits across one of the largest utility companies in the United States.

In light of these extreme amounts, a more attractive approach may be to increase the capacity factor at coal-fired power plants situated where there is no risk of water-related constraints. Fortunately, this idea is made plausible by the absence of transmission bottlenecks across the state as declared by the latest Department of Energy (DOE) Electric Transmission Congestion Study.[33] Unfortunately however, even though there are numerous coal-fired generation units outside the Central and Southern Piedmont Regions that might help in this regard, they will also be running at full capacity during periods of peak demand; precisely the time when extra generation capacity is needed. The natural gas plants are in a position to contribute because they are typically in operation for only 2-3 hours of the day for peaking – standing idle the rest of the time. Other solutions available to buffer against blackouts include energy efficiency, water conservation programs as well as potential investments in renewable energies that use comparatively smaller amounts of water – these will be explored later.

5.5 Summary of cost impacts for switching to natural gas

Under the case just discussed, a utility company would typically wait for a severe drought to occur and then respond accordingly. An alternative approach would involve taking steps to protect the company position before any such event happened. To meaningfully explore this option, one must first ascertain how much the utility company involved can justifiably spend.

1. Costs of switching to Natural Gas (ascribed to differences in generation costs)

   We have already established that with roughly 5900 MW under questionable reliability in times of severe drought, the following costs are likely to be incurred at least once every 30 years (based on historical Palmer Drought Severity Index Data). Recall that the different costs incurred for the considered scenarios are as follows:

Table 6: Range of cost impacts from switching to natural gas power plants which have higher per kWh generation costs

Mode used to cover 5900 MW shortfall	Discount rate	NPV of extra costs (after 30 years)
Switch to operating natural gas power plants	0.0%	$194 million
	7.0%	$30 million
Purchasing extra natural gas (+20% Natural Gas price increase)	0.0%	$646 million
	7.0%	$85 million
Purchasing extra natural gas (+40% Natural Gas price increase)	0.0%	$754 million
	7.0%	$99 million
Electricity imports	0.0%	$323 million
	7.0%	$45 million

2. Extra cost incurred due to anticipated sharp increase in natural gas prices

   In addition to the increase in marginal costs of production, one must also account for the impact such an increase in demand for electricity from peaking plants will have on the regional price of natural gas. Using the arithmetic in the previous section, we see that the prices for natural gas could increase by anywhere from 20% to 40%. Using a baseline summer season natural gas price of US12 per 1000 ft^3 and the anticipated demand increase, it is implied then, that prices during the severe drought will range from US$14.4 to US$16.8 per 1000 ft^3. The extra expenditure on natural gas is likely to be in the region of US$ 640 million to US$ 754 million over the entire summer or peak season.

   There will be demand side responses to a higher prices for natural gas and electricity. These responses will tend to decrease natural gas consumption and ease the spike in price levels if the drought persists.

5.6 The financial cost of a blackout in North Carolina

<u>The State-wide economic impact</u>

In addition to costs incurred by the investor-owned utility companies, there are other major impacts that North Carolina could have to contend with. If utility companies cannot make up the electricity supply shortfall, rolling blackouts and brown-outs may occur. The benefit of avoiding these costs may lead to state authorities providing some form of assistance to the utilities to ensure added counter measures against the adverse effects of drought.

It is extremely difficult to quantify impacts to the economy largely because of unforeseen cascading effects. One of the ways to approximate the potential impact may be to look at similar incidents in the past. With such an approach, one identifies states which have suffered blackouts and share a similar economic profile with North Carolina. This gives an idea of the order of magnitude associated with such an incident.

In 2003, the Anderson Economic Group released an impact analysis of the blackout that occured in the Northeastern United States earlier in the same year. The incident affected 8 states to varying extents. Each of these 8 will be compared to North Carolina in terms of their economic profile (i.e. the sectors which contribute the most to state GDP). This comparison will serve as a proxy measure for the vulnerability of the state to electricity blackouts. The states affected in the 2002 blackouts were: New York, Michigan, Vermont, Pennsylvania, Ohio, Connecticut, Massachusetts and New Jersey. The following table discloses some basic metrics used to characterize each of the states affected.

<u>Table 7</u>: Contribution to GSP of major sectors in states affected by the 2003 electricity blackout[34]

State/territory	Government	Manufacturing	Finance/insurance	Technical services	Health care
New York	10.0	6.0	17.9	8.4	7.2
New Jersey	10.3	8.8	8.3	9.0	7.2
Connecticut	9.0	12.7	16.5	7.4	7.4
Vermont	13.7	11.5	5.9	5.9	10.0
Ohio	**11.1**	**18.2**	**8.1**	**5.8**	**8.2**
Michigan	11.3	16.9	6.1	8.1	8.1
Massechusetts	8.8	9.9	10.6	11.3	9.2
Pennsylvania	9.8	14.2	7.5	7.6	9.6
NORTH CAROLINA	**12.9**	**18.6**	**12.7**	**4.9**	**6.2**

In terms of the metrics used above, North Carolina is most similar to Ohio. Both states are characterized by high proportions of GDP associated with the government and manufacturing sectors, while their respective combinations of financal, technical services and health care in terms of contribution to state GDP are most similar out of any of the possible pairings.

Total economic impact was quantified using data on lost earnings as well as spoiled goods and higher electricity costs across all relevant states. The table below shows the costs sustained by each of the mentioned states:

Table 8: Economic losses to each state affected by 2003 blackout in the NE United States[35]

	State GSP (2001), Base Year (billions)	State GSP (2002), estimate (billions)	State GSP (2003) (billions)	1-day GSP (billions)	Earnings (billions)	Total Lost Earnings * (billions)	Fraction Affected Day 1	Fraction Affected Day 2	Fraction Affected Day 3
Michigan	$ 320.5	$ 332.0	$ 351.0	$ 1.0	$ 0.8	$ 0.7	*40.0%*	*40.0%*	*5.0%*
New York	$ 826.5	$ 856.3	$ 905.2	$ 2.5	$ 2.0	$ 2.0	*40.0%*	*40.0%*	*20.0%*
New Jersey	$ 365.4	$ 378.6	$ 400.2	$ 1.1	$ 0.9	$ 0.3	*25.0%*	*5.0%*	*0.0%*
Ohio	$ 373.7	$ 387.2	$ 409.3	$ 1.1	$ 0.9	$ 0.4	*25.0%*	*15.0%*	*0.0%*
Pennsylvania	$ 408.4	$ 423.1	$ 447.3	$ 1.2	$ 1.0	$ 0.1	*10.0%*	*5.0%*	*0.0%*
Connecticut	$ 166.2	$ 172.2	$ 182.0	$ 0.5	$ 0.4	$ 0.1	*10.0%*	*5.0%*	*0.0%*
Vermont	$ 19.1	$ 19.8	$ 21.0	$ 0.1	$ 0.0	$ 0.0	*5.0%*	*0.0%*	*0.0%*
Massachusetts	$ 287.8	$ 298.2	$ 315.2	$ 0.9	$ 0.7	$ 0.0	*0.5%*	*0.0%*	*0.0%*
Total	**$ 2,767.5**	**$ 2,867.5**	**$ 3,031.1**	**$ 8.3**	**$ 6.6**	**$ 3.5**			
Sources:	*BEA*	*BEA & AEG Est.*	*AEG Projection*	*BEA & AEG*	*BEA & AEG*	*AEG*			

Table 8 shows that with an electricity supply disruption of only **2 days**, with each day only suffering supply shortages between 15% and 25% of generation capacity, economic losses are in the region of US$0.4 billion in Ohio State. Actual losses for North Carolina are likely to be about 10-15% smaller in absolute terms because annual gross state product in Ohio is at approximately US$466 billion while North Carolina is smaller at roughly US$400 billion.[36] With losses estimated at $0.2 billion each day, this dimension of economic loss is by far the most important for authorities to consider – potentially amounting to **US$12 billion over 3 months (US$0.2 billion per day 60 working days).** Very importantly, we note that this wider economic cost is one that does not factor into the investment decisions of the privately-owned utility yet it affects the wider state economy.

6. The <u>expected value</u> of financial loss and the justifiable expenditure to counter the effects of drought

Now that we have calculated the costs associated with switching to natural gas, importing electricity, price spikes in natural gas and economy-wide losses, we must account for the probability of such scenarios occurring to arrive at the **expected financial loss**. This is the value that a company would be willing to spend on drought countermeasures. One decision tool often used in industry for this type of problem is a simple Probability Analysis. Probabilistic methods are useful in aiding decisions where the probability distribution of given events is known or can be estimated with acceptable accuracy.

In our calculation of expected values, the following approach will be used:

1. Define a domain of possible inputs.
2. Generate inputs from the domain. (i.e. use historical data to find the probability of each level of drought occurring)
3. Perform a deterministic computation using the inputs (i.e. quantify the loss for each possible severe drought event)
4. Find expected value using deterministic computation and cumulative probability distribution

In this scenario where economic loss is incurred due to drought, the 4 steps will be executed as follows:

1. **Define a domain of possible inputs**

The determinant of whether an economic/financial loss is incurred depends on whether a drought of Severity Index -3.5 or less occurs. Values for the Palmer Drought Severity Index range from -6 to 6.

2. **Generate inputs randomly from the domain**

For the randomly generated inputs, we use the Palmer Drought Severity Indices from the the last 100 years. This is the same data that was used to generate the histograms seen earlier in this report such as those in Figures 20, 24 and 27.

3. **Perform a deterministic computation using the inputs**

The deterministic computation is conducted using the following conditional formulas

x	=	Palmer Drought Severity Index
L(x)	=	Loss associated with any year when a drought of Palmer Severity Index (x) occurs
If $x \leq -3.5$		then L(x) equals **\$193 815 000** (if electricity shortfall is covered by natural gas plants)
If $x \leq -3.5$		then loss equals **\$323 025 000**(if shortfall is covered by electricity imports at peak rates)
If $x > -3.5$		then L(x) equals **\$0**

To account for increases in the price of natural gas, we simply adjust the number used for the loss in any one year, and add the extra expenditure that comes with having to pay for higher natural gas prices.

For example: Losses due to switching to natural gas power plants are **$193 815 000**

5900 MW shortfall from nuclear and coal plants shutdown must be covered by intermediate and peaking natural gas plants. Making up for this capacity means consuming an extra 44,921 million ft^3 of natural gas in the year when the severe drought occurs. We have also noted that under normal circumstances, the summer (peak season) price for natural gas is in the region of US$12 per 1000 ft^3. Therefore:

If natural gas price increases by 20%, then extra expenditure is:
($12 x 1.2) x 44 900 000 = US$ 646 560 000 over the peak season

If natural gas price increases by 40%, then extra expenditure is:
($12 x 1.4) x 44 900 000 = US$ 754 320 000 over the peak season

To account for the losses sustained by the state economy in the event of blackouts, we use the financial losses estimated in the previous section. (i.e. US$ 12 billion over 60 working days or 3 months).

Once the final level of financial/economic loss in calculated, it must then be discounted in accordance with the year in which the drought occurs and the chosen discount rate.

Now the EXPECTED financial loss is calculated by mulitiplying the loss under a given scenario with the probability that that specific sceanrio will occur. The Excel table overleaf shows how this is done – the expected values are presented graphically in Figure 30 on the following page. After factoring in the probabilities of each level of drought occuring, the numbers along the bottom row of Table 9 represent expected losses.

Table 9: Demonstrated calculation of probability adjusted expected losses

						Loss of buying extra Natural Gas			
Bin range	*Frequency*	*Cumulative %*	*Probability*	*Loss to utility*	*Loss to utility (imports)*	NG price effect (20% increase)	NG price effect (40% increase)	NG price effect (doubling price)	*Loss to state economy*
-5.5	2	0.15%	0.001463058	283562.5457	472604.2429	1228697.879	1386708.12	1860153.621	17556693.49
-5.0	4	0.44%	0.002926116	567125.0914	945208.4857	2457395.757	2773416.24	3720307.242	35113386.98
-4.5	8	1.02%	0.005852231	1134250.183	1890416.971	4914791.514	5546832.48	7440614.484	70226773.96
-4.0	11	1.83%	0.008046818	1559594.001	2599323.336	6757838.332	7626894.66	10230844.92	96561814.19
-3.5	19	3.22%	0.013899049	2693844.184	4489740.307	11672629.85	13173727.14	17671459.4	166788588.1
-3.0	29	5.34%	0.021214338	0	0	0	0	0	0
-2.5	76	10.90%	0.055596196	0	0	0	0	0	0
-2.0	107	18.73%	0.078273592	0	0	0	0	0	0
-1.5	119	27.43%	0.087051939	0	0	0	0	0	0
-1.0	119	36.14%	0.087051939	0	0	0	0	0	0
-0.5	128	45.50%	0.093635699	0	0	0	0	0	0
0.0	105	53.18%	0.076810534	0	0	0	0	0	0
0.5	90	59.77%	0.065837601	0	0	0	0	0	0
1.0	133	69.50%	0.097293343	0	0	0	0	0	0
1.5	127	78.79%	0.09290417	0	0	0	0	0	0
2.0	93	85.59%	0.068032187	0	0	0	0	0	0
2.5	81	91.51%	0.059253841	0	0	0	0	0	0
3.0	45	94.81%	0.0329188	0	0	0	0	0	0
3.5	41	97.81%	0.029992685	0	0	0	0	0	0
4.0	15	98.90%	0.010972933	0	0	0	0	0	0
4.5	6	99.34%	0.004389173	0	0	0	0	0	0
5.0	1	99.41%	0.000731529	0	0	0	0	0	0
5.5	4	99.71%	0.002926116	0	0	0	0	0	0
6.0	2	99.85%	0.001463058	0	0	0	0	0	0
More	2	100.00%	0.001463058	0	0	0	0	0	0
				6,238,376	10,397,293	27,031,353	30,507,579	40,923,380	386,247,257

Expected values

Using the method described in the previous two pages, the bar graph directly below is generated to illustrate the financial losses:

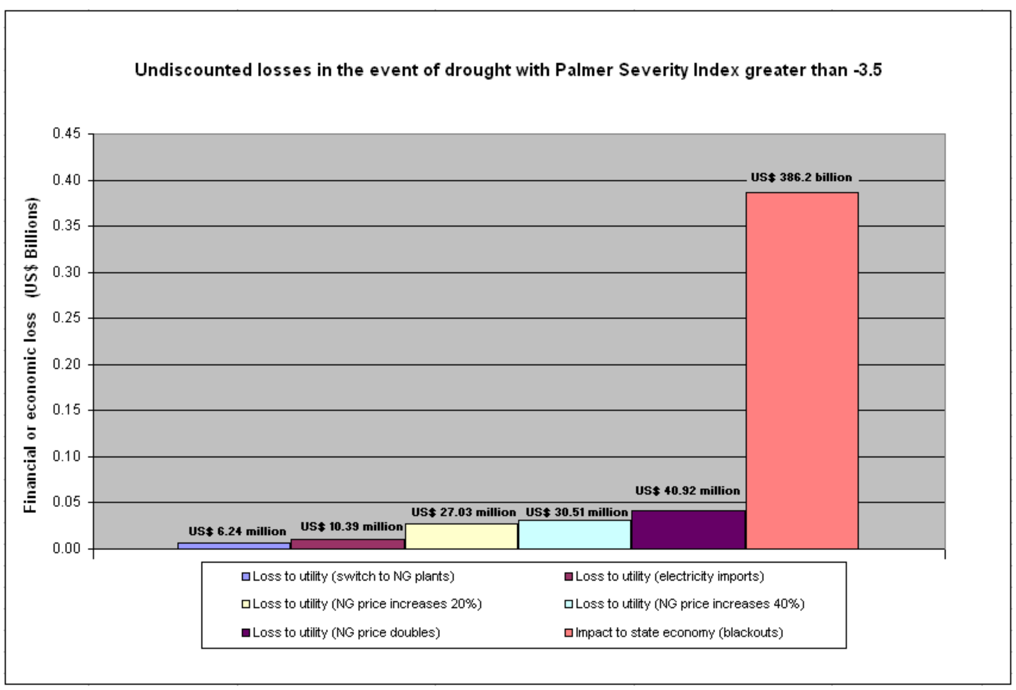


Figure 30: Expected financial/economic loss due the drought-related power outages

The Probability Adjusted Expected Losses for each of the scenarios are as follows:

Table 10: Summary of costs under different drought-related scenarios

Mode used to cover 5900 MW shortfall	Discount rate	NPV of extra costs (after 30 years)	Probability adjusted NPV of extra costs * (after 30 years)
Switch to operating natural gas power plants	0.0%	$194 million	$6.24 million
	7.0%	$30 million	**$820 000**
Switch to operating natural gas (+20% Natural Gas price increase)	0.0%	$646 million	$27.03 million
	7.0%	$85 million	$3.55 million
Switch to operating natural gas (+40% Natural Gas price increase)	0.0%	$754 million	$30.51 million
	7.0%	$99 million	$4.01 million
Electricity imports	0.0%	$323 million	$10.39 million
	7.0%	$45 million	$1.36 million
Economic loss to state (in event of blackouts)	0.0%	$12 billion	$386.2 million
	7.0%	$1.58 billion	$50.73 million

***Adjusted to include the probability of a drought of severity >-3.5 occuring**

The numerical values presented in the table above represent the high and low extreme estimates for economic losses. The present value for losses occuring in the future is calculated using a discounting factor as in the following example:

Cost of switching to Natural Gas Plant = $194 million

The Discount Factor is

$$P(T) = \frac{1}{(1+r)^T}$$

Where: r is the discount rate

T is the year (from present) when the drought occurs.

So for example:

The probility adjusted cost of switching to Natural Gas in 30 years because of a drought (assuming electricity demand and supply capacity remain the same), and a 7% discount rate is calculated as:

$6.24 million x $[1/(1+0.07)^{30}]$ = **US$820 000** (written in bold red text in the table above)

7. What are the options for countering the adverse effects of drought?

7.1 The Energy Efficiency Option

The prospect of (avoiding) the economic losses calculated in the previous section may be used as a basis for investing in energy efficiency programs. It is important to specify the type of efficiency programs to more accurately quantify the associated costs and savings expected. Studies have been done which group such programs into 4 categories namely:

- **Appliance standards**

  National standards have been established for an array of household appliances including: refrigerators, dishwashers, clothing dryers, washers and air conditioners. Standards have also been set for lighting fixtures as well as residential and commercial heating and cooling equipment.

- **Demand-side management**

  Utility based programs cover a variety of approaches including financial incentives (tarriff restructuring), load management and load shifting (away from peak demand periods). Utility companies have also attempted to change consumer demand for different types of energy services thereby increasing market penetration of energy efficient practices. This process consisted of equipment demonstrations, incentives, training and public awareness campaigns.

- **Information and voluntary programs**

  The Environmental Protection Agency (EPA) and Department of Energy (DOE) jointly run the voluntary efficiency labelling program, Energy Star, which provides information on the relative energy efficiency of products. It was designed to reward the most energy efficient manufacturers with good publicity and improve marketing of their products. The program now covers a wide range of products including computers, monitors, home electronics, and even entire buildings.

- **Management of energy use by federal government** (largest US energy consumer).

  Within government, efficiencies may be improved primarily in official buildings. Efficient office equipment and air-conditioning systems may be set as requisite on procurement contracts when government equipment is due for replacement.

The table below shows cost estimates on different energy efficiency initiatives as evidenced by past experience in North Carolina. The estimates are of normalized average programme implementation costs.

Table 11: Typical costs associated with energy efficiency and conservation programs[37]

	Present Value of Total Costs (2006 $)	Value of Lifetime kWh Savings - Customer Meter Level	Levelized Cost per Lifetime kWh Saved
Residential Sector	$262,528,658	9,673,701,174	$0.027
Commercial Sector	$352,185,339	8,702,321,930	$0.040
Industrial Sector	$124,388,270	6,805,459,342	$0.018
Total - All Sectors	$739,102,267	25,181,482,446	$0.029

The most important column in the table for determining how far each investment dollar goes is column 4 titled "Levelized Cost per kWh Saved".

7.1.1 Savings from efficiency

To illustrate the calculation involved, we will use the average cost estimate for implementation of energy efficiency across all sectors. Here we see (from Table 11) that US$0.029 is required to effect a saving of 1 kWh.

In SI units, the per savings expenditure = US$29.00 per MWh

From the utility companies point of view (since the loss to the economy is not borne by the utility but by society at large), only a maximum of about US$30.51 million would be justified expenditure based on the probability of a severe enough drought happening, the costs implications of switching over to natural gas fired power and a 40% increase in the price of natural gas (see Figure 30). With this level of earmarked finances, the following savings are achievable using energy efficiency programs:

US$30.51 million ÷ 29.00 = 1052068.966 MWh

The financial losses computed were for a drought occuring in a single year; hence savings of 1052068.966 MWh occur over the same basis period of 1 year. Assuming that this saving is continuously available, this equates to an available nominal capacity of:

1052068.966 MWh ÷ (365 x 24) = **120.1 MW**

7.1.2 Savings from weatherizing homes

In March of this year, the Obama-Biden Administration announced nearly US$208 million in Weatherization Funding and Energy Efficiency Grants for North Carolina. The split between the two purposes was $131,954,536 for the Weatherization Assistance Program and $75,989,000 for the State Energy Efficiency Program.[38] The funding will support weatherization of homes, including adding more insulation, sealing leaks and modernizing heating and air conditioning equipment. It has long been recognized that such an emphasis on energy efficiency and weatherization pays for itself many times over both in terms of avoided costs from the wider economy (in the even of electricity shortages) and accrued benefits over time.

If we assume that US$30.51 million can justifiably be spent by privately held utilities, and also that the spending mirrors the $6500 per home spent in the Obama-Biden plan,[38] then this level of spending could potentially help roughly 4 700 households across the state. Moreover, the energy savings typically associated with such programs is 20-30% of the heating bill in low income homes.

7.2 Opting for renewable technologies.

7.2.1 Wind power

North Carolina has approximately 10 000 MW of potential wind energy resource.[39] This amounts to over a third of already-existing installed generation capacity throughout the state. Despite this substantial wind resource, less than half of it is available for development due to consideration for vulnerable species and sensitive ecosystems where the wind farms would be built. Altogether, approximately 3000 to 4000 MW of wind capacity is legally and economically feasible. We may however, see how far we can deploy only the *justified* expenditure in countering the effects of drought based on the expected losses calculated earlier.

In May 2008, the United States Department of Energy released a comprehensive report on trends in the wind generated industry which disclosed that, installation costs for wind power are currently at roughly US$ 1500 per kW. The trend over the last two and a half decades is shown in the graph below:

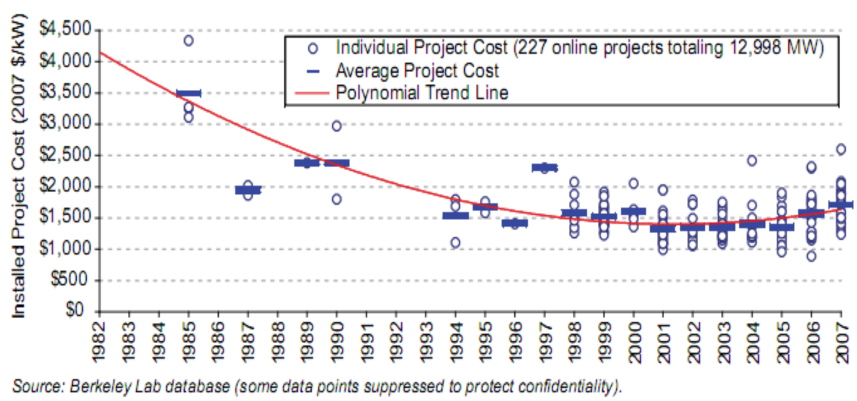


Figure 31: Wind power installation costs over the last 25 years[40]

From this trend we see that installation costs have declined over time but are not likely to decline any further. At US$1500 per kW, and with a maximum of US$30.5 million to spend on water-efficient energy supply technologies, the amount of addition nameplate (nominal) capacity that may be added to the North Carolina mix is:

US$30.51 million ÷ 1500 = 20,340 kW ≈ **20.34 MW**

20.34 MW is well below the levels of effective savings achievable through energy efficiency. Opting to use earmarked funds for wind power would not be cost effective. It is also worth noting that 20.34 MW is the nominal capacity installed and that in reality less energy will be delivered into the state grid after operational capacity factors are taken into account.

7.2.2 Solar Power

The latest trends in the solar industry show that manufacturing costs for solar photovoltaics are approaching the US$1 per Watt level.[41] This has only been achieved by a handful of solar technology vendors (e.g. First Solar Inc) and is not the industry norm yet. As other corporations continue to innovate and the manufacturing processes disseminate through the sector, costs should gravitate towards this level and hopefully also decrease further. In light of this, we use US$1 per Watt to see how much solar power may be delivered to market in North Carolina.

With a one-to-one dollar to Watt ratio, US$30.51 million should enable procurement of **30.5 MW** of solar PV capacity. Not included here are costs associated with installation – hence the estimate of 30.5 MW is very optimistic and in any event much smaller than the energy saved through efficiency initiatives.

8. Quantifying upward pressure on electricity prices with incremental shutdown of base load power

Over this entire paper, an implicit assumption has been made that the major nuclear and coal plants are either fully operational of fully brought offline due to drought-related water constraints. In reality, there may be variations on these scenarios and in this brief section, an attempt is made to identify the point at which net income of the utility companies starts to come under pressure as production at natural gas plants is ramped up.

To do this, the generation cost supply curve is used in conjunction with the load duration curve as explained earlier in the methods section of this report. The more accurate supply and demand curves are shown on Figure 32 on the following page. Also depicted directly below is the growth in electricity demand from 2006 to 2007.

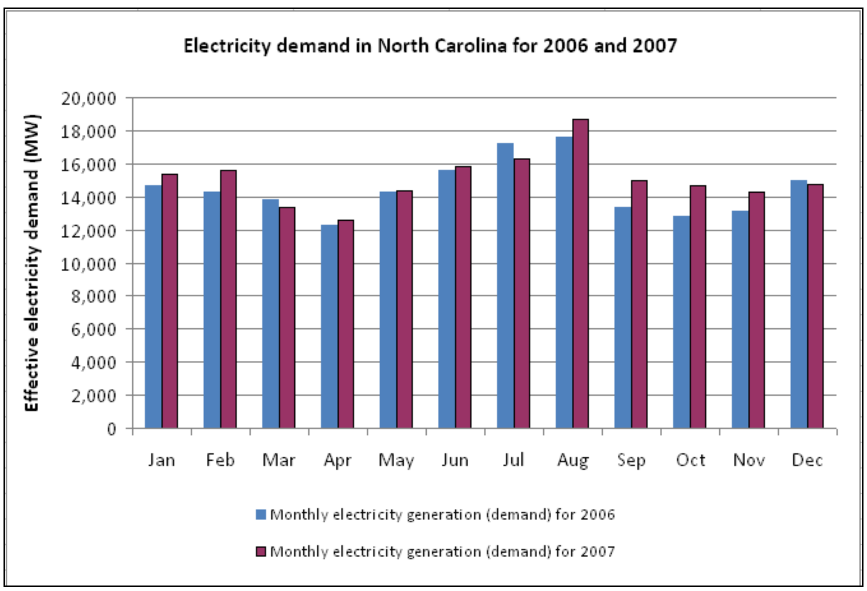


Figure 6: Month-by-month electricity consumed in North Carolina for 2006 and 2007

On this graph, we see that for the majority of months, the demand has increased albeit by a small amount. In July, March and December however, electricity demand was greater in 2006 than in 2007. If demand was (for the most part) greater in 2007, this implies that the load duration curve will have shifted slightly to the right as compared to 2006. This shift of the demand curve to the right is also shown in figure 32 (green demand curve is for 2007 demand).

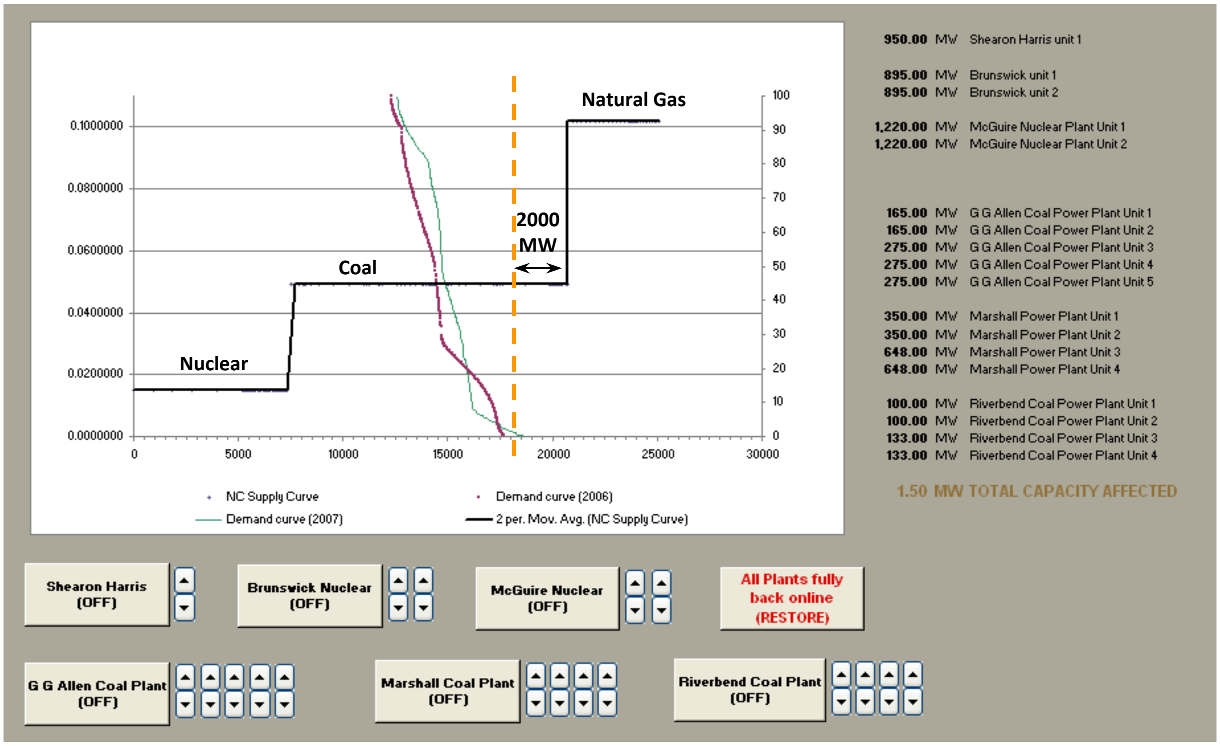


Figure 32: Generation cost supply curve and load duration curve to ascertain buffer capacity until NG plant are operated continuously.

The visual shows that at 2007 electricity demand levels, there is still buffer capacity from coal power plants. This buffer covers some of the electricity shortfall from the plants situated in water-stressed areas. The orange vertical line in Figure 32 shows the peak demand for electricity in 2007 at about 18500 MW. According to the Annual Energy Outlook of 2007, peak electricity demand is expected to grow at 2%. Applying this rate for years 2007, 2008 and 2009 implies that at the end of 2009, annual peak electricity demand will be closer to 19,600 MW.

At this demand level, the buffer capacity offered by the intermediate coal plants would be negligible and virtually all electricity supply that cannot be supplied by water-stressed nuclear and coal plant would be deferred to peaking natural gas power plants. In the graph on the next page (Figure 33) we see how the 3000 MW buffer we had on average beforehand in 2006, is turned into a 4000 MW deficit at 2007 peak electricity demand levels (see Figure 33 on the next page). Given the growth in peak demand, the shortfall for 2009 will be between 5000MW and 6000MW, in line with the assumption of 5900 MW that we have used in the calculations conducted in this report.

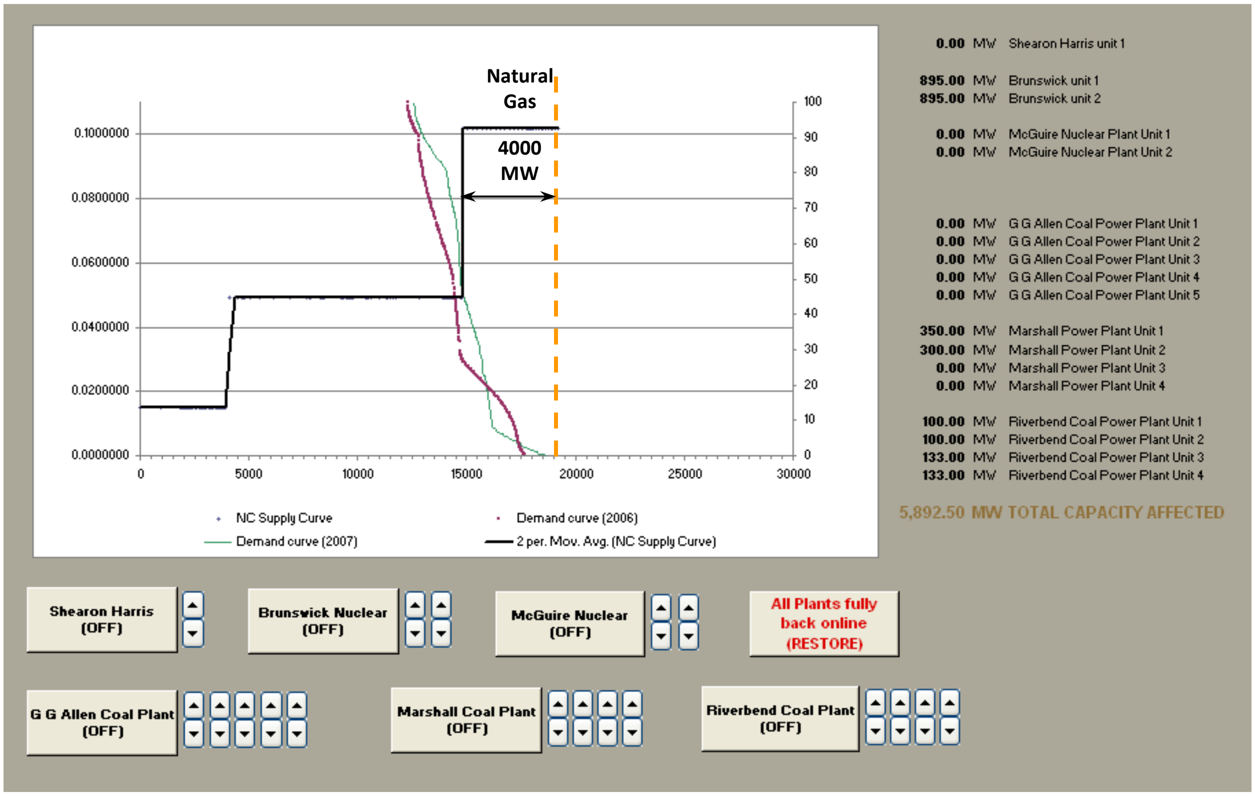


Figure 33: Generation cost supply curve and load duration curve showing no buffer capacity at 2009 peak electricity demand levels.

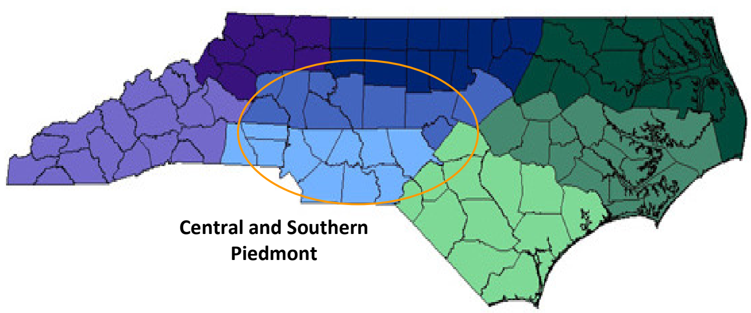
9. Summary of results and conclusions

9.1 Impact of drought in North Carolina

Although the southeastern United States is a region that frequently experiences extended dry periods, it is actually quite rare that droughts are so severe that operations at thermo-electric power plants are stopped. For this to occur, droughts would have to persist for an extended period at a Palmer Severity Level of at least -3.5 to -4. Taking North Carolina as an average, this has only happened less than 5 times over the last century.

9.2 Areas of concern within North Carolina

Of the 9 climatic regions in North Carolina, only the *Southern and Central Piedmont Regions* exhibit tendency for the levels of drought severity that cause problems for power plant operations. Within these 2 regions is a combined 5900 MW of generation capacity which may be compromised in the event of severe drought. 5900 MW amounts to just over 50% of state baseload generation capacity and less than 25% of total generation capacity. The central and southern Piedmont Regions are highlighted by the circle in the map below:



9.3 Expected loss to operator of generation units

Based on the probability of each level of drought occurring and the price of natural gas increasing by up to 40%, the aggregated expected loss to the corporations running the generation units in these regions is summarized in the table below:

Mode used to cover 5900 MW shortfall	Discount rate	NPV of extra costs (after 30 years)	Probability adjusted NPV of extra costs * (after 30 years)
Switch to operating natural gas power plants	0.0%	$194 million	$6.24 million
	7.0%	$30 million	**$820 000**
Purchasing extra natural gas (+20% Natural Gas price increase)	0.0%	$646 million	$27.03 million
	7.0%	$85 million	$3.55 million
Purchasing extra natural gas (+40% Natural Gas price increase)	0.0%	$754 million	$30.51 million
	7.0%	$99 million	$4.01 million
Electricity imports	0.0%	$323 million	$10.39 million
	7.0%	$45 million	$1.36 million
Economic loss to state (in event of blackouts)	0.0%	$12 billion	$386.2 million
	7.0%	$1.58 billion	$50.73 million

The amounts of money in the final right-hand column may justifiably be set aside by a private corporation for investments in water-efficient energy supply technologies such as energy efficiency, wind and solar power.

9.4 Effective capacity that may be made available with justifiable funds

The table below summarizes the additional power generation that may be *installed* or made available using the earmarked funds computed as the expected present value of losses (i.e US$30.51 million in losses to utilities if undiscounted;).

Technology Option	Amount of nameplate capacity installed
Energy efficiency	Approx. 120.1 MW
Wind Power	Approx. 20.34 MW
Solar Power	Approx. 30.51 MW (only accounting for manufacturing costs – not installation)

If funds are made available based on expected present value losses to the economy (i.e. US$386.2 million in losses to the state if undiscounted), then 12 times more capacity will be made available to alleviate the adverse effect of drought. The amount of additional power achievable from US$386.2 million in spending is shown overleaf:

Technology Option	Amount of nameplate capacity installed
Energy efficiency	Approx. 1520.2 MW
Wind Power	Approx. 257.5 MW
Solar Power	Approx. 386.2 MW (only accounting for manufacturing costs – not installation)

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