Applied Energy 206 (2017) 267–277

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Electricity demand planning forecasts should consider climate non-stationarity to maintain reserve margins during heat waves

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HIGHLIGHTS

- Weather-adjustment methods in electricity infrastructure planning are biased.
- Climate models project temperatures up to 58 °C (136 °F) in the US Desert Southwest.
- Peak demand does not increase linearly with temperature; s-curve more accurate.
- Los Angeles could experience hazardous power shortages in record-breaking heat.
- Risk management strategies identified via reductions in peak load & load variance.

ARTICLE INFO

Keywords:
Climate non-stationarity
Electric power infrastructure
Peak demand
Risk management
Structural equation modeling

ABSTRACT

Climate non-stationarity is a challenge for electric power infrastructure reliability; recordbreaking heat waves significantly affect peak demand [1], lower contingency capacities, and expose cities to risk of blackouts due to component failures and security threats. The United States' electric grid operates safely for a wide range of load, weather, and power quality conditions. Projected increases in ambient air temperatures could, however, create operating conditions that place the grid outside the boundaries of current reliability tolerances. Advancements in long-term forecasting, including projections of rising air temperatures and more severe heat waves, present opportunities to advance risk management methods for long-term infrastructure planning. This is particularly evident in the US Southwest—a relatively hot region expected to experience significant temperature increases affecting electric loads, generation, and delivery systems. Generation capacity is typically built to meet the 90th percentile (*T90*) hottest peak demand, plus an additional reserve margin of least 15%, but that may not be sufficient to ensure reliable power services if air temperatures are higher than expected. The problem with this *T90* planning approach is that it requires a stationary climate to be completely effective. In reality, annual temperature differences can have more than a 15% effect on system performance. Current long-term infrastructure planning and risk management processes are biased climate data choices that can significantly underestimate peak demand, overestimate generation capacity, and result in major power outages during heat waves.

This study used downscaled global climate models (GCMs) to evaluate the effects of non-stationarity on air temperature forecasts, and a new high-level statistical approach was developed to consider the subsequent effects on peak demand, power generation, and local reserve margins (LRMs) compared to previous forecasting methods. Air temperature projections in IPCC RCPs 4.5 and 8.5 are that increases up to 6 °C are possible by the end of century, with highs of 58 °C and 56 °C in Phoenix, Arizona and Los Angeles, California respectively. In the hottest scenarios, we estimated that LRMs for the two metro regions would be on average 30% less than at respective *T90*s, which in the case of Los Angeles (a net importer) would require 5 GW of additional power to meet electrical demand. We calculated these values by creating a structural equation model (SEM) for peak demand based on the physics of common AC units; physics-based models are necessary to predict demand under unprecedented conditions for which historical data do not exist. The SEM forecasts for peak demand were close to straight-line regression methods as in prior literature from 25–40 °C (104 °F), but diverged lower at higher temperatures. Power plant generation capacity derating factors were also modeled based on the electrical and thermal performance characteristics of different technologies. Lastly, we discussed several strategic options to

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http://dx.doi.org/10.1016/j.apenergy.2017.08.141
Received 17 March 2017; Received in revised form 29 June 2017; Accepted 12 August 2017
0306-2619/

reduce the risk of LRM shortages; including implementing technology, market incentives, and urban forms that reduce peak load and load variance per capita as well as their tradeoffs with several other stakeholder objectives.

1. Introduction climate stationarity assumptions in long-term electricity infrastructure planning

Some risk management practices in the electric power sector use "rules of thumb." One of these rules is to build at least a 15% surplus of power generation to meet peak demand [2], where contingency capacity or generation "head room" is needed if units go offline. Maintaining a reliable margin is risky business because peak demand changes over time as a result of variations in population, human behavior, technology, and climate [3]; moreover, infrastructure implementations are costly and long-term investments. The electric power industry currently considers all of these factors in planning processes; however, they do not plan for climate non-stationarity [4–7]. Climate non-stationarity affects planning in two ways, wherein changing atmospheric conditions can result in different annual probability distributions of air temperatures [8], as well as differences in low, average, and high air temperatures [9]. The common practice in industry is to plan for future peak demand based on a 90th percentile, also referred to as *T90* or 1-in-10 hottest days, summertime temperature using historical (stationary) probability distributions [6,10]. Peak demand is generally understood to change with temperature during the seasons in many geographic regions, but little knowledge exists in environmental studies to model that relationship beyond historical correlations [11–16]. With a lack of peer-reviewed literature on the topic, studies can easily, and mistakenly, assume correlation implies causation when assessing the risk of rising air temperatures on infrastructure systems. Accurate scientific knowledge is necessary to maintain reliability in electric infrastructure systems if climate conditions are significantly different in the future.

Failure to properly understand and plan for grid performance at unprecedented high temperatures could result in blackouts. Multiple service interruptions have recently occurred during heat waves due to transformer overloads, transmission line faults, generation shortages, and cascading failures [17–20]. While grid operators can ramp power generators up or down to respond to sub hourly changes in load [21], those capabilities are physically limited by plant type, total production capacity, and bottlenecks in electrical delivery systems–all of which are determined through long-term planning processes [3]. If the forecasting methods are not accurate, and engineering tolerances are not sufficient, then contingency capacities could be negatively impacted and component hardware failures could be triggered; systems could be exposed to security threats [22,23], higher probability of blackouts [24], and unnecessary operations costs [3].

Local reserve margin (LRM) is a contingency capacity metric equal to the amount of generation that exceeds the aggregate peak demand within a geographic area. The "local" boundary can be a neighborhood, a substation region, a utility service territory, or several territories, and may or may not include "remote" generation and "long-distance" transmission lines [6,25–31]. Transmission import capabilities are out of the scope of local generation, and are dependent upon generation headroom in other connected local areas. These imports allow for a reduction in LRM regulatory requirements by enabling delivery of non-local resources [32]. Specific requirements for LRMs vary regionally with consideration for factors such as the reliability of components, likelihood of concurrent peak loads in neighboring regions, and security [25–27,33].

In this study, we examined assumptions about air temperatures used in long-term infrastructure planning processes, including the lack of consideration for annual differences in heat wave severity (non-stationarity), and corresponding methods for forecasting peak demand, generation capacity, and LRMs, which could result in power shortages. We used county lines for Los Angeles and Maricopa (Phoenix) to define local areas for LRMs because these geopolitical boundaries reasonably frame the existing infrastructure, and public data were readily accessible in that format. We used global climate model (GCM) simulations of the Intergovernmental Panel on Climate Change's Representative Carbon Pathway scenarios RCP 4.5 and RCP 8.5 to define a range of possible future air temperatures in addition to historical ranges from local weather stations. We modeled how existing infrastructure operates differently across the range of historical and future air temperatures using previous statistical methods from the literature and our own structural equation modeling approach. We did not attempt to predict physical changes in future supply- or demand-side infrastructure or complete a full planning scenario necessary for legislating local resource adequacy and transfer capacity requirements. Specifically, we studied the effects of stationarity assumptions on long-term planning estimates of (1) air temperatures, (2) peak demand, (3) generation capacity, and (4) LRM. We used our quantitative models and results as the premise for a qualitative discussion of options to mitigate the risk of LRM shortages.

2. Methods: Air temperature effects on peak demand, generation capacity, and LRMs

We chose the Phoenix and Los Angeles regions to study because they are the two largest cities in the US Southwest and have growing populations and aging infrastructure that require immediate investments [5,34,35]. These regions are already amongst the hottest in the world, are expected to have significant temperature increases in the future [1,11], and were feasible to study because they exist largely within county boundaries for which public data are available. First, we characterized ranges of local temperatures within and across Los Angeles, California and Maricopa, Arizona for recent historical samples of *T90* and GCM projections of future high temperatures for RCP 4.5 and RCP 8.5. Second, we fit two statistical models to historical data to predict peak demand as a function of air temperature. We used a straight-line regression approach, as in previous studies, and developed our own model based on AC performance at varying T_{max}. The nature of our model is that it has multiple levels of equations with terms that fit simultaneously as both predicted and predictor variables; this type of multiple regression analysis is called structural equation modeling (SEM) [36]. As explained in detail in SI Section 1, we chose to focus the majority of our analytical efforts on modeling peak demand because seasonal changes in peak demand are an order of magnitude higher than changes in generation capacity, which are an order of magnitude higher than any delivery system losses. We did not consider losses in any form. Third, we used derating factors from previous studies of power plant operations to estimate decreases in capacity as a function of T_{max} by generator fuel technology. Fourth and finally, we used results of those analyses to calculate LRM, and analyzed the effects of stationarity assumptions in the above aspects of LRM planning.

2.1. Local air temperatures

We parameterized a range of daily high air temperatures (T_{max}) using historical weather station data obtained from [37], and future projections from downscaled Localized Constructed Analogs GCM models through the end of century [38]. To quantify a range of temperature values for the stationarity approach, we sampled T_{max} from June, July, August, and September during the early-century period (2001–2016) from four weather stations in each county located where