Characterizing Generation Mix and

Virtual Water for Resilience to Drought

on the Western U.S. Power Grid

by

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A Thesis Presented in Partial Fulfillment
of the Requirements for the Degree
Master of Science

Approved July 2013 by the
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August 2013

ABSTRACT

There is growing concern over the future availability of water for electricity generation. Because of a rapidly growing population coupled with an arid climate, the Western United States faces a particularly acute water/energy challenge, as installation of new electricity capacity is expected to be required in the areas with the most limited water availability. Electricity trading is anticipated to be an important strategy for avoiding further local water stress, especially during drought and in the areas with the most rapidly growing populations. Transfers of electricity imply transfers of "virtual water" – water required for the production of a product. Yet, as a result of sizable demand growth, there may not be excess capacity in the system to support trade as an adaptive response to long lasting drought. As the grid inevitably expands capacity due to higher demand, or adapts to anticipated climate change, capacity additions should be selected and sited to increase system resilience to drought. This paper explores the tradeoff between virtual water and local water/energy infrastructure development for the purpose of enhancing the Western US power grid's resilience to drought. A simple linear model is developed that estimates the economically optimal configuration of the Western US power grid given water constraints. The model indicates that natural gas combined cycle power plants combined with increased interstate trade in power and virtual water provide the greatest opportunity for cost effective and water efficient grid expansion. Such expansion, as well as drought conditions, may shift and increase virtual water trade patterns, as states with ample water resources and a competitive advantage in developing power sources become net exporters, and states with limited water or higher costs become importers.

ACKNOWLEDGEMENTS

I would like to acknowledge several people who, through their effort and dedication, made this work possible. First, I would like to thank my adviser Benjamin Ruddell for his guidance and vision in shepherding this work. I would like to thank collaborator Lucy Qui for her economic insights and assistance in building the model. Additionally, I would like to thank Vincent Tidwell and Eric Vulgrin from Sandia National Laboratory for providing direction and data for this work.

Thank you to co-chair Samuel Ariaratnam for your advice and attention to detail. Thank you Braden Allenby for asking insightful questions and convincing me to come to ASU. And thank you Eric Williams for your continued support and for taking a chance by bringing me on as a new student to this field.

This work was made possible in part by the U.S. National Science Foundation's Resilient and Sustainable Infrastructures grant EFRI 0836046 and by The Sustainability Consortium, who supported me during the past academic year.

Finally, I would like to thank my friends and family for their love, support, and patience with me throughout this process.

TABLE OF CONTENTS

Page

Page

LIST OF TABLES

Tables Page

LIST OF FIGURES

INTRODUCTION

Water is a critical input for electric power production. Thermoelectric power plants require water to absorb waste heat from energy conversion, while hydroelectric plants power their turbines using the downhill flow of water. Yet, there is growing concern over the future availability of water for this sector. A spate of incidences over the past decade have revealed the vulnerability of electric power production to water shortages. Thermoelectric power production has been compromised by droughts in Europe (in 2006), the US Midwest (in 2006), the US Southeast (in 2007, 2010, and 2011), India (in 2010), and Texas (in 2011) resulting in increased rates or rolling blackouts (Dell, 2010; Boogert & Dupont, 2005; Averyt, et al., 2011; Jowit & Espinoza, 2006; Hardikar & Mehta, 2010). Droughts in the Pacific Northwest (in 2001), California (in 2007), and Southwest Europe (in 2008) severely limited available hydro generation, forcing utility operators to buy power at greatly inflated prices (Bonneville Power Administration, 2002; Dell, 2010). Population growth trends and predicted water shortages due to climate change suggest that such events will become more common in the future.

Water energy challenges are particularly acute in the Western United States. Here, groundwater levels are already declining and climate change could decrease streamflow by as much as 10-30% (U.S. Department of Energy, 2006; Chan, Duda, Forbes, Rodosta, Vagnetti, & McIlvried, 2006). Yet, the rapid population growth in this region shows no sign of waning (National Energy Technology Laboratory, 2011). California alone is anticipated to increase its population by 50% by 2030 (Hancock, Chung, & Mills, 2004). Because of these population growth trends, installation of new electricity capacity is expected to be required in the areas with the most limited water availability (Tidwell, Kobos, Malczynski, Klise, & Castillo, 2012). As a result of increased electricity demands, water consumption by thermoelectric power plants is expected to rise by 10-28% (National Energy Technology Laboratory, 2011).

Since water availability is limited in many locations with increasing electricity demands, electricity trading will be an important strategy for avoiding further local water stress, especially during drought and in the areas with the most rapidly growing populations. As there is water embedded in almost all electricity trades, transfers of electricity imply transfers of "virtual water" – water required for the production of a product (Lenzen, 2009). This outsourcing of water for electric power production is a viable method for avoiding local water use, but creates vulnerability to droughts occurring in the supplier's water basin. The existing trend in virtual water trade in the Western US is to increase total water use through this supply outsourcing, which exacerbates water scarcity issues (Adams, Rushforth, Ruddell, & Tidwell, in review). Additionally, trade in virtual water via electricity purchases on the spot market is currently the most common response to local electricity shortages due to drought (Harto & Yan, 2011). But this practice assumes that such power will be available. In the case of a widespread, long lasting drought, there may not be excess capacity in the system to support such trades. Therefore, as the grid inevitably expands, capacity additions should be selected and sited to increase system resilience to drought. Planning the electrical grid for system-wide water constraints is a more effective method of building resilience than planning water and energy systems separately (Lall & Mays, 1981).

This paper explores the tradeoff between virtual water and local water/energy infrastructure development for the purpose of enhancing the Western US power grid's resilience to drought related supply shortages. To that end, a linear optimization model is developed that estimates the configuration of the Western US power grid that will ensure a reliable electricity supply during short and long-term drought while maximizing profit for producers. The model treats each of the eleven states in the Western Electricity Coordinating Council (WECC) region as independent units for energy/water infrastructure decisions. For each kWh generated beyond the capacity of existing water supplies and existing generation and transmission system, the model determines each state's highest profit option for meeting electrical demands (among developing low-water energy infrastructure or purchasing electricity from neighbors).

While many studies have analyzed future water availability for electricity generation as well as the current electricity grid's vulnerability to drought (Yan, Tidwell, & King, 2013; Ackerman & Fisher, 2013; Harto & Yan, 2011; Sovacool & Sovacool, 2009; U.S. Department of Energy, 2013), there is no example in the literature of a large scale, least cost electricity generation model that satisfies water constraints during extreme drought. Lall & Mays (1981) and Matsumoto & Mays (1983) build least-cost optimization models of water-energy systems, though they limit their analysis to eastern Texas and do not include drought simulation in their planning scenarios. UC Berkeley's Renewable and Appropriate Energy Laboratory develop a large-scale planning model used to optimize the Western electricity grid for low costs while meeting low carbon policy goals, though water constraints are not explicitly considered (Wei, Nelson, Ting, & Yang, 2012). This study also contributes to the virtual water literature by comparing its effectiveness in providing low cost electricity to the alternative option of developing local water resources to support electricity production. Drought simulations enable exploration of how changes in regional water availability affect virtual water trade. Such analysis is unique to this study.

This paper addresses the following research questions: (1) Between virtual water trades and local water/energy resource development, which is most economically optimal for the purpose of enhancing the Western US power grid's resilience to drought related power supply shortages, (2) In each Western US State, for the first kWh generated beyond the capacity of existing water supplies during a drought, what is the most cost effective generation method (on the margin) depending on the duration, intensity, and geographic extent of the drought, (3) What state-level attributes determine a state's response to drought and demand increases, (4) Do thresholds of demand increase or drought severity exist where dramatic changes will be needed to the power grid, and (5) How does the embedded water content of electrical power and the total Western US water savings due to electrical energy trade change as a result of adaptation of the power grid to increased demand and drought?

BACKGROUND

Increasing Demand for Electricity

Population pressure is increasing the total demand for electricity, especially in the rapidly growing Western US. Despite decreasing per capita energy use due to energy efficiency measures, total energy use is expected to increase through the foreseeable future. In the next 20 years, per capita electricity use is expected to shrink by ~10%, but population will increase by 0.9% per year. Consequently, electricity use is projected to increase by 20% in the next 30 years (U.S. Energy Information Administration, 2013).

Increased temperatures due to climate change may also cause greater increases in electricity usage. Although, on a net usage basis, temperature increases in the summer months may potentially be offset by decreases during the winter months, summer increases can push the limits of generation capacity. As temperatures increase, so too do building cooling loads. During these times, electricity prices dramatically increase, and if demand reduction strategies are not implemented, generation and/or transmission may reach their limits, leading to operators resorting to rolling blackouts.

Increased temperatures due to climate change are projected to have negative impacts on the efficiency of power generation and distribution. Natural gas power generating capacity could decrease by 3-6%. Transformer and substation capacity could diminish by 2-4%. Distribution loses could increase by 1-3%. And transmission line capacity could decrease by 7-8%. Because of the cumulative effect of these inefficiencies, parts of the grid may require ~30% more capacity than would be expected from population growth alone (Sathaye, et al., 2012).

Increasing Frequency of Water Shortages

At the same time that electricity is expected to be in greater demand, water supplies are becoming less secure. Climate concerns and declines in groundwater levels suggest that there will be a net reduction in freshwater availability in the future (U.S. Department of Energy, 2006). Streamflow in the Western US could decrease by as much as 10-30% (Chan et al, 2006).

A changing climate will introduce greater variability in the amount of surface water available for electric power production and other users (Atlantic Council, 2011). For example, snow pack provides roughly 75% of the water supply in the West and is a key component of water storage. Although the Colorado River can store several times its annual flow rate due to large reservoirs, other rivers such as the Columbia can store much less (only 30% of annual flow). When warm temperatures bring rain instead of snow, or snow melts earlier than usual, reservoirs may not have the capacity necessary to store the early flow. This can lead to water shortages in the summer months, just as high temperatures increase evaporation rates (U.S. Department of Energy, 2006). For example, The Sierra Nevada Mountains in California are expected to release an increasing amount of flow earlier than usual – in the winter rather than spring – as a result of climate change (Hancock, Chung, & Mills, 2004). Even the water-rich Pacific Northwest is expected to see summertime disruptions of hydropower generation of up to 15.4% because of changes in annual streamflow runoff patterns (U.S. Department of Energy, 2013).

While surface water supplies are insecure, groundwater supplies are already being overdrawn. Freshwater withdrawals already exceed precipitation level in many areas of the country, especially in the West, and consequently, available water in aquifers all over the country is decreasing (U.S. Department of Energy, 2006). When withdrawal rates exceed recharge rates, water must be pumped from greater depths. As aquifers are drawn down, they may yield brackish water that must be treated before entering a thermoelectric cooling system, thus increasing energy use and decreasing the efficiency of the plant. Ultimately, there is a risk that aquifers can become fully depleted, resulting in a loss of water supplies (U.S. Department of Energy, 2006).

Increases in population put further stress on water resources. To complicate matters, population increases have largely occurred in water-stressed areas (National Energy Technology Laboratory, 2011). California alone is anticipated to increase its population by 50%, up to 51 million people by 2030, increasing urban and industrial water uses by ~35% (Hancock et al, 2004). As a result, 36 states anticipate water shortages in the next 10 years under normal water conditions, while 46 states anticipate water shortages during droughts, according to a 2003 study conducted by the Congressional General Accounting Office (Feeley III, Green, Murphy, Hoffmann, & Carney, 2005).

Unlike some environmental concerns, such as climate change, which arguably occur gradually enough for management and technological innovations to address, water shortages can occur without warning. Sudden reductions in water availability can cripple local and national economies (Myhre, 2002). The possibility of sudden, severe droughts is backed up by the historic record (Woodhouse, Meko, MacDonald, Stahle, & Cook, 2010).

Water Used for Electricity Production

While, this study is primarily concerned with the water used by thermoelectric and hydroelectric plants to generate electricity, it must be noted that water is used throughout the life cycle of the electrical power generation system. Solar panels and other materials, such as steel, used in power plant infrastructure require water to produce. Organic materials burned in biomass plants are grown using water. Coal and natural gas are extracted and refined via processes that use water (Badr, Boardman, & Bigger, 2012). However, these upstream processes represent a small fraction of the total water consumed for energy production. Even for water efficient thermoelectric plants that use recirculating cooling, upstream processes account for only 10-20% of water consumed. The proportion of water withdrawal that takes place upstream at a water inefficient thermoelectric plant is negligible. Life cycle water consumption for renewable energy technologies, such as solar PV and wind, is almost exclusively associated with upstream manufacturing, as these technologies consume almost no water during the use phase (Fthenakis & Kim, 2010).

Water withdrawals for thermoelectric cooling represent nearly half of all water withdrawals in the United States (Kenny, Barber, Hutson, Linsey, Lovelace, & Maupin, 2009). By comparison, water for irrigation accounts for ~30% and the public supply is ~10% (Wu & Peng, 2010). These withdrawals represent 200 billion gallons of water everyday, a fourfold increase in water withdrawals since 1950 (Wu & Peng, 2010). Of that number, 4 billion gallons are consumed (Atlantic Council, 2011). If new power plants continue to be built with evaporative cooling, withdrawals could double by 2030 (U.S. Department of Energy, 2006). Between 2000 and 2005 alone, water withdrawals for thermoelectric generation increased 3% (Wu & Peng, 2010).

Illinois, Michigan, Ohio, Tennessee, and Texas are the states that withdraw the most water for electricity generation. These states alone represent one third of the water withdrawn for electricity generation and 25% of the electricity generated (Wu & Peng, 2010). Even in the Southwest, which withdraws less water for thermoelectric power than any other region on the US, power plants withdraw an average of 125-190 million gallons of groundwater per day.

According to Wu & Peng (2010), an average of 13.9 gal of freshwater is withdrawn, and 0.39 gal consumed for each kWh of electricity produced in the United States. Approximately 93% of the water used by thermoelectric power plants is for cooling. Other processes that use water include scrubbers, ash control, steam used to drive turbines, and washing the cooling systems (Badr et al, 2012).

Cooling water. In thermoelectric power plants, water is used to absorb waste heat from energy conversion. Cooling water is used to convert boiler water from steam back to a liquid for reuse. Thermoelectric power plants operate by first boiling water to steam. This water/steam mix is called boiler water. The steam is then driven through a turbine, which rotates and generates electricity. The steam is then passed into a condenser where it interacts with pipes containing cooling water and is converted back to a liquid to be reused in the boiler. The cooling water is drawn in from an external source, and when it has absorbed the heat from the steam, it is released back into the environment (Badr et al, 2012).

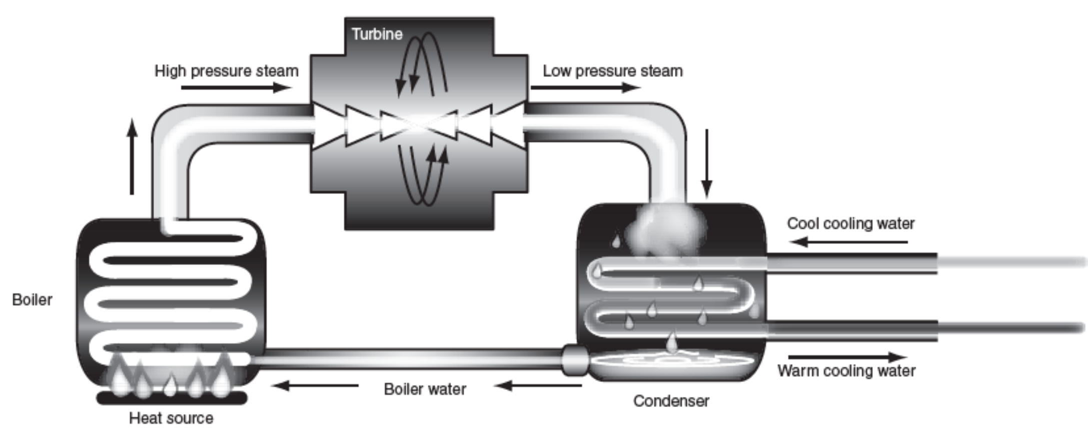


Figure 1. *Cooling System in Thermoelectric Power Generation (US GAO, 2009).*

Yang & Dziegielewski (2007) study the parameters that affect the water-use per kWh in thermoelectric plants. They find that the characteristics of a power plants that most affect plant water withdrawals are (1) operational efficiency (eg, unadjusted pumping systems are inefficient and may pump more water required than required), (2) average rise in cooling water temperature from inflow to outflow, (3) thermal efficiency of the plant, and (4) outside air temperature (warm water is less efficient at absorbing heat from steam).

Water consumption factors for thermoelectric power plants show more significant variation between cooling types than between fuel types (Macknick, Newmark, Heath, & Hallett, 2011). See the figures below for details.

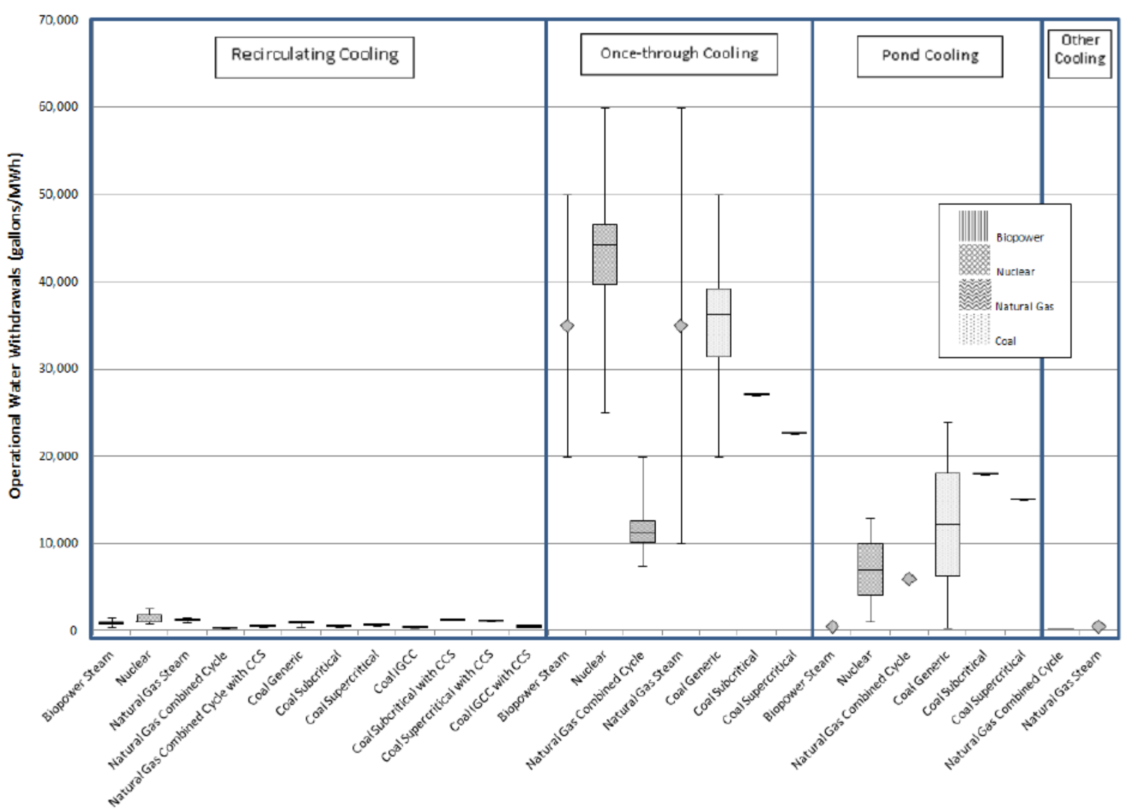


Figure 2. *Water Withdrawals for Power Generation (Macknick et al, 2011).*

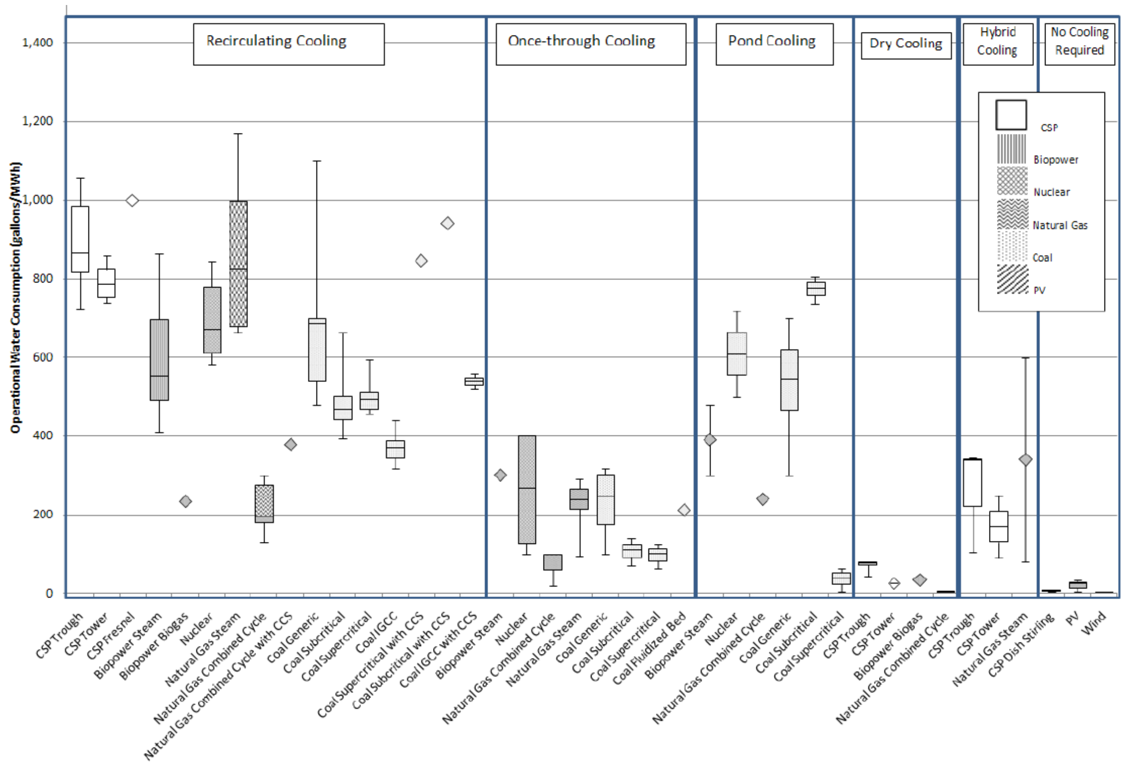


Figure 3. *Water Consumption for Power Generation (Macknick et al, 2011).*

The following sections describe the three main types of cooling systems: once through, wet-recirculating, and dry. Hybrid systems also exist that combine elements from wet and dry recirculating cooling. Note that it requires a considerable infrastructure investment for a plant to upgrade its cooling system type (U.S. Government Accountability Office, 2009).

Also included below are descriptions of the differences in water use patterns between various types of thermoelectric power plants including coal, natural gas, nuclear, biomass, geothermal, hydroelectric, renewables, as well as carbon sequestration technologies. The main points of this section are as follows: (1) Water efficiencies of power plants are largely determined by cooling system type rather than fuel input type. Once through systems withdraw large amounts of water and are highly vulnerable during droughts. Recirculating cooling systems withdraw much less water, but consume all of it. Because of water availability concerns, almost all thermoelectric plants in the Western US use recirculating cooling systems. (2) Of the fossil fuel plant types, natural gas combined cycle (NGCC) is the most water efficient, while supercritical coal plants are the least. NGCC plants contain both a steam turbine and a combustion turbine, the latter of which requires no water to operate. During droughts, NGCC plants can therefore operate without water, albeit at lower efficiencies. (3) Hydropower generation requires that water pass through the system in order to generate electricity. In this way, water is required, but not consumed for hydro generation. (4) Carbon sequestration technologies are expensive and require large amounts of water to be effective. While there exists the possibility that future regulations will one day require these technologies to be deployed, their high cost and water consumption precludes their use in this analysis.

Once through. Sometimes referred to as “open loop”, this type of cooling system withdraws considerable amounts of water (usually from a surface water source), runs it through a heat exchanger to cool the plant, and then returns the warmed water back to the source. 92% of all water withdrawals for thermoelectric power production in the US come from the plants equipped with once-through cooling systems (Kenny et al, 2009).

To protect aquatic ecosystems, The Clean Water Act §316 contains regulations on the temperature at which water from once-through cooling systems can be returned to surface waters (Badr et al, 2012). During heat waves, these regulations can becomes prohibitive. At coal-fired power plants, discharge temperatures are, on average 17 degrees F hotter than intake temperatures. At nuclear facilities with once-through cooling systems, discharge temperatures can be 30 degrees F higher than the source (Atlantic Council, 2011).

Because it is thermodynamically efficient and historically inexpensive, most thermoelectric plants built before 1970 employ this technology. However, because of the difficulty obtaining a permit due to water availability concerns, new once-through plants have become increasingly rare (Badr et al, 2012).

Approximately one third of electricity generated in the United States is produced at a coal or nuclear facility employing a once-through cooling system (Wu & Peng, 2010), and about 43% of existing thermoelectric power plants use a once-through cooling system (Gerdes & Nichols, 2008).

Wet-recirculating. Also called “closed loop” cooling, this system withdraws 10-100 times less water than once-through systems (Macknick et al, 2011). Like once-through systems, the water is run through heat exchangers to cool the plant, but then it is itself cooled in either ponds or towers. In cooling towers, water flows over high surface area packing, maximizing its contact with cooling air, which is moved through the tower via either mechanical fans or natural air currents (Gerdes & Nichols, 2008). Cooling ponds are shallow pools in which water sits until returning to near ambient air temperature. Pond-systems can be operated in manners that resemble once-through or recirculating systems, and thus vary in water withdrawal and consumption (Macknick et al, 2011).

Once the excess heat in the water has dissipated, it can be used again. Because the water is repeatedly reused, a much larger percentage of the amount withdrawn is consumed (via evaporation or leakage) than in once-through systems. Recirculating systems consume approximately twice as much water as once-through systems (Macknick et al, 2011).

Because these systems require more power to operate than once-through systems, they decrease the efficiency of power plants. Wet recirculating systems are also roughly 40% more expensive than once-through cooling systems (Gerdes & Nichols, 2008). The majority of power plants in the West and Southwest use recirculating cooling systems, with wet towers being about 4x more common than ponds (Cooley, Fulton, & Gleick, 2011).

Dry cooling. Dry cooling systems do not use water for cooling. Instead, fans blow air onto the coils containing the steam exiting the turbines. This configuration reduces water used by the plant by 75-90% (Badr et al, 2012). However, because electricity is required to operate the fans and pumps, dry cooling systems are less efficient than wet cooling systems. Plant output is reduced by approximately 2% per year (Maulbetsch, 2004). Additionally, the efficiency of this scheme decreases as ambient air temperatures increase – as much as 8-25% during the hottest days of the year. This makes the dry, arid climates of the West less conducive to dry cooling systems (U.S. Department of Energy, 2006). Less than 1% of electricity in 2009 was produced using a dry cooling system (Badr et al, 2012). Dry cooling systems are also 3-5 times more expensive than wet cooling systems (Gerdes & Nichols, 2008).

Coal. Pulverized coal plants are either subcritical or supercritical. Subcritical plants are among the least water efficient type of thermoelectric power plant because they use low steam pressure and therefore must use more steam to compensate. Supercritical plants are somewhat more water efficient. Pulverized coal plants also require flue gas desulfurizers, which employ a slurry of 10% limestone and 90% water, increasing the water requirements of these types of plants (Gerdes & Nichols, 2008).

Integrated gasification combined cycle plants use significantly less water than pulverized coal plants. This mainly due to the fact that the gas turbine, which requires minimal cooling water, produces roughly two-thirds of the plants electric output. In these plants, cooling water is also required for a number of other process steps such as air separation, acid gas removal, tail gas treating, and the coal gasification process itself (Gerdes & Nichols, 2008).

Nuclear. Nuclear plants use more water per power output than any other thermoelectric plant (by fuel type). Nuclear plants generally use steam of lower temperature and pressure than other power generation types because the nuclear reactor makes the metal piping in the plant more brittle. More steam is therefore needed in order to drive turbines, which requires more cooling water relative to the power produced (Gerdes & Nichols, 2008).

Natural gas. Simple natural gas combustion plants require no water at all, as the gas itself is used to fuel a combustion turbine. However, these plants are generally expensive and inefficient to operate, and are therefore only used mainly during peak load hours.

Natural gas steam plants are more efficient than gas combustion plants, but use water comparable to coal plants. Natural gas combined cycle power plants, however, contain both steam turbines and gas combustion turbines, and are more water efficient that coal-fired or nuclear power plants (U.S. Department of Energy, 2006), consuming only 0.1 gallons of water per kWh produced (Wu & Peng, 2010). This is due to the fact that two-thirds of a combined cycle power plant's output comes from the combustion turbines, which require minimal water compared to the steam cycle (Gerdes & Nichols, 2008). In fact, if no water were available for cooling, operators could shut down the steam cycle of the power plant, and still be able to operate the plant at roughly two-thirds capacity (Poch, Conzelmann, & Veselka, 2009).

For a 500 MW combined cycle plant, use of dry-cooling would reduce plant water use by 2,000-2,500 acre-feet per year. However, this would increase plant costs by 5-15%, decrease annual revenue by 1-2%, decrease annual energy production by 1-2%, and reduce capacity on hot days by 4-6% (Maulbetsch & DiFilippo, 2006).

Biomass. Biomass electricity plants use dried vegetation as a fuel source. Typical biomass burned for power are agricultural, industrial, and municipal waste such as wood waste, switchgrass, cottonwood trees, and burnable garbage. Biomass plants use water to condense steam back to boiler water so it can be reused to drive a turbine, just as in other thermoelectric power plants. Like other thermoelectric power, biomass plants can employ once-through, recirculating, or dry cooling systems (Office of Indian Energy and Economic Develpment, n.d.).

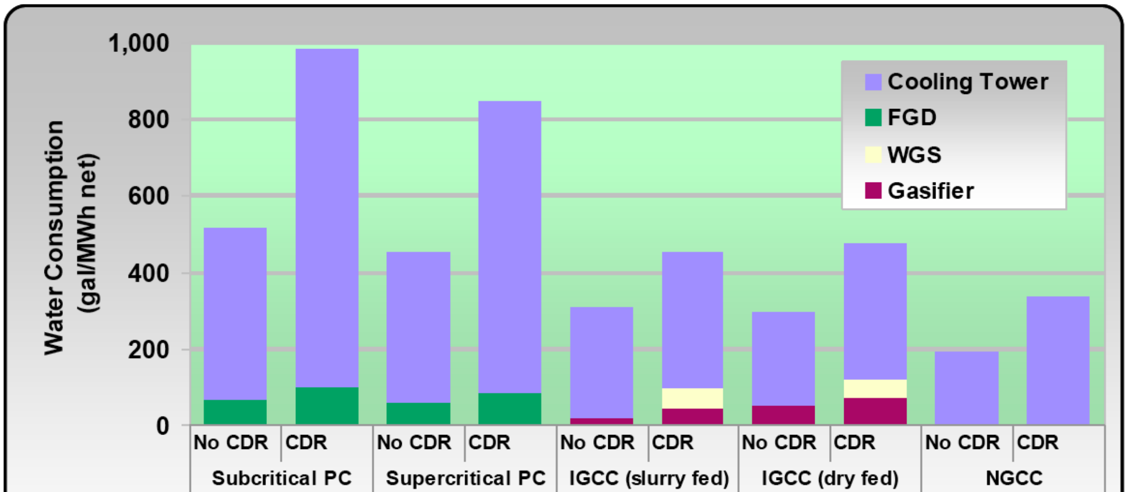
Geothermal. Geothermal plants come in two categories: vapor-dominated dry-steam systems and liquid-dominated hot water systems. In the dry-steam system, vapor from an underground well directly runs the steam turbine. The steam condensate is then used for cooling. In the hot water system, the hot, pressurized liquid (or mix of liquid and vapor) is brought to the surface where it is depressurized to release steam which then drives the turbine. Geothermal plants tend to use more water than conventional steam turbine plants because of their low heat to electricity conversion efficiency (8-15%) (Fthenakis & Kim, 2010).

Hydroelectric. The US alone has over 79,000 dams (McMahon & Price, 2011). Hydroelectric plants are operated by the downhill flow of water powering a turbine. They are versatile because, as long as there is ample water behind the dam, they can be ramped up or down quite quickly to provide power as needed. Pumped-storage hydroelectric plants can pump water upstream during low demand periods and release it during high demand periods (Lin, Huang, Li, & Li, 2012).

Hydroelectric plants require ~440 gal/kWh to operate (Cooley et al, 2011), but they do not consume any water in the traditional sense. Instead, water loses associated with hydroelectric plants are a result of evaporation from the high surface area reservoirs that serve as fuel for the plants (McMahon & Price, 2011). While the water that passes through hydroelectric plants is generally disregarded in embedded water calculations (Scott & Pasqualetti, 2010), Mekonnen & Hoekstra (2011) suggest that this evaporative loss is significant.

PV and wind. Renewable sources of electricity such as wind farms and solar photovoltaics use very little water – approximately less than one gal/MWh (Atlantic Council, 2011) – for periodically cleaning the equipment. Of the renewable energy technologies, wind is installed in the largest capacity in the United States (U.S. Department of Energy, 2006). However, some renewable technologies require much more water. Concentrated solar power (also called solar thermal, which includes a steam cycle) uses 800-900 gallons/MWh (Atlantic Council, 2011).

Carbon sequestration. Carbon capture and sequestration technologies can require 80% more water than conventional electricity generation (Atlantic Council, 2011). The CO_2 recovery system involves a number of subprocesses, which collectively require a significant amount of cooling water. These include flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, and CO_2 compression interstage cooling (Gerdes & Nichols, 2008). Because of this additional water cost, carbon sequestration technologies are excluded as generation options in this analysis.



	No CDR	CDR	No CDR	CDR	No CDR	CDR	No CDR	CDR	No CDR	CDR
	Subcritical PC		Supercritical PC		IGCC (slurry fed)		IGCC (dry fed)		NGCC	
Total	517	985	452	844	309	452	295	475	192	338
Cooling Tower	449	884	392	759	290	355	243	355	192	338
FGD	68	101	59	86						
WGS						52		49		
Gasifier					19	45	53	71		

Figure 4. *Water Requirements for Thermoelectric Power Plants with and without Carbon Dioxide Recovery (National Energy Technology Laboratory, 2008).*

Drought in the Western United States

In their literature survey on drought in the 20th century, Harto & Yan (2011) find that most extreme droughts have the following characteristics:

- The precipitation shortage is greatest during the winter
- The largest snow water equivalent reduction occurs in March and April, putting snow-fed water supplies at greatest risk
- The worst deficit of soil moisture and snow-melt runoff is in May and June and are unlikely to fully recover (reaching only 80%) in the year after the extreme drought
- The average summer temperature is 0.1 – 5 °C higher than normal

Additionally, Harto & Yan (2011) find that droughts lasting 5 years have occurred every 20-30 years during the past century, while a drought of >10 years has occurred only once in the Western US (in the Pacific Northwest basin during the 1930s). Yet, yearlong droughts reoccur every 8 years on average. Droughts lasting >10 years have also occurred in the Pacific Northwest during the 1600's and 1800's, and in the Colorado River Basin during the 1600's.

While climate change is anticipated to increase drought frequency and severity throughout the US (U.S. Department of Energy, 2013), The Southwestern and Rocky Mountain states are projected to see the largest increases in drought frequency (Averyt, et al., 2011). Much of the water supplied to these states comes from the Colorado River. Despite being able to store more than four times its annual runoff (with the aide of two large reservoirs – Lake Powell and Lake Mead), the US Bureau of Reclamation (2012) projects that demand for Colorado River water will outstrip supply in the foreseeable future. While the Colorado has significant buffering capacity against shortages (runoff has been below normal for 10 years and users have not been affected), other rivers have limited storage, and would likely see significant flow reductions during droughts lasting a few years (Harto & Yan, 2011).

While shorter, 1-year, 5-year, and to some extent 10-year droughts have occurred according to a somewhat predictable pattern (Harto & Yan, 2011), there remains the possibility of longer term, more severe drought. Historical drought measurements conducted via tree ring analysis by Woodhouse et al (2010) over the past 1,200 years reveals the possibility of future severe, long-lasting drought in the Southwestern US. While these events are rare, they have occurred in the past and may potentially occur again.

Drought Effects on Power Production

Utilities that heavily rely on fresh surface water from rivers are the most susceptible to decreases in power production or increases in the cost of production in the event of drought (Palmer & Lund, 1986). The most common concern among electricity generators during a drought is a drop in hydroelectric production. Reduced flow in rivers and reduced head in reservoirs can greatly decrease the capacity factor of hydropower during droughts (Palmer & Lund, 1986).

Thermoelectric power production may be affected by a reduction in cooling water availability, with water levels occasionally falling below cooling water intake pipes. Increasing temperatures of available surface water cause reduced cooling efficiency as the thermal differential between the cooling water and the steam in the condenser shrinks. When cooling water discharge exceeds the levels stipulated by Clean Water Act §316, plant operators are obligated to scale back or halt power production (Kimmell & Veil, 2009).

Additionally, droughts are frequently accompanied by temperature increases, which drive up the demand for electricity as air conditioner loads increase. Electricity demands for groundwater pumping may also increase as surface water becomes less available. During the 1976 California drought, electricity used for groundwater pumping increased by 20% (Palmer & Lund, 1986).

Historic Cases of Electricity Supply Disruption During Drought

During the California drought of 1976 – 1977, Pacific Gas and Electric (PG&E) experienced a shortage of hydroelectricity, and was forced to buy power on the market from other service providers and rely on thermoelectric power. As a result, PG&E's operating expenses and carbon emissions increased dramatically (Harto & Yan, 2011).

From October 2000 through September 2001, the Pacific Northwest experienced an energy crisis. This crisis was largely due to a steep drop in hydroelectric production, as runoff volume dropped to less than 60% of average. This shortage of production forced utilities to buy power at greatly inflated prices (Bonneville Power Administration, 2002). There were no outages, but the economic impacts were high – between $2.5 and $6 billion in the region of the drought (Harto & Yan, 2011).

In 2003, an exceptionally hot summer in continental Europe caused electrical power disruptions. The heat wave reduced flow while increasing temperatures in rivers. This compromised hydro generation and put pressure on thermoelectric cooling capability. Many countries chose to temporarily ignore exhaust-water temperature ceilings rather than shut down plants. This was especially true for countries that heavily rely on nuclear power, such as France and Germany, because nuclear power plants are difficult to quickly start and stop. Even wind power was largely unavailable due to a lack of wind (Bruch, Munch, Aichinger, Kuhn, Weymann, & Schmid, 2011). Electricity prices increased dramatically. Still, there were power shortages. France, one of Europe's top exporters, reduced its generation capacity and had to cut exports. Consequently, Italy, which usually relies on French power during similar crises, had to resort to rolling blackouts in major cities to deal with the shortage (Boogert & Dupont, 2005).

Another European heatwave in the summer of 2006 caused water shortages that lead to thermoelectric power plants being shut down. Spain shuttered one of its eight nuclear reactors, which collectively supply a fifth of the country's electricity. Germany and France were both forced to cut output at nuclear plants or issue special permits that allowed cooling water discharge above the normal threshold (Jowit & Espinoza, 2006). In northern Italy, the River Po suffered from a drought, which dried up part of its course. Hydroelectric production in that part of the river had to be cut by 75%. Two large thermoelectric power plants that normally draw water from the river were forced to cut production for lack of cooling (Dell, 2010).

A 2006 heat wave in the Midwest forced a Minnesota plant was forced to cut electricity generation by more than half because of high temperatures in the Mississippi River (Averyt, et al., 2011).

Droughts in California during 2007 caused hydroelectric generation by the utility company PG&G to drop from 22 to 13 percent of their delivery mix. The result was a 39% increase in PG&G’s greenhouse gas emission rate for that year (Dell, 2010). Southwest Europe faced the same issue in the summer of 2008, when drought caused a lack of hydropower generation and a subsequent increase in coal-fired generation (Dell, 2010).

In August of 2007, after months of drought, a heat wave swept through North Carolina. Water levels in the Catawba River, which is the source of cooling water for seven major thermoelectric power plants, were low just as demand for electricity hit an all-time high. Because cooling-water discharge exceeded safe temperature limits for fish in the river, Duke Energy was forced to cut generation at two large coal-fired power plants, resulting in blackouts throughout the area. A month later, Duke Energy had to modify a water intake pipe for a 2,200 MW nuclear plant to remain below the dropping water level in Lake Norman (Averyt, et al., 2011).

The Tennessee Valley authority has had trouble maintaining operations at their Browns Ferry nuclear facility during recent summers. In 2007, 2010, and 2011, temperatures in the Tennessee River rose above 90 °F, ensuring that cooling water discharge temperatures would exceed regulated limits. In each year, the plant was forced to cut back operations until river temperatures decreased. The resulting shortfall in electric power was made up through purchases of high priced power, costing ratepayers $50 million (Averyt, et al., 2011).

In 2010, after a year of insufficient rains, the Irai dam in the Indian state of Maharashtra was at 8% of capacity, forcing closure of all units of the 2340 MW coal plant, Chandrapur Super Thermal Power Station, which is the largest thermal power plant in the state. The closure caused blackouts of between two and six hours per day in nearby rural communities. After ramping down generation through the winter, the plant closed all units on May 15th, and did not resume operation until rains came later in the summer (Hardikar & Mehta, 2010).

In the summer of 2011, at the end of the driest 10 months on record, Texas was water short. Some of its rivers, such as the Brazos, had dried up. The dry weather was accompanied by a heat wave that brought electricity demand to record-breaking levels. One plant had to curtail operations for lack of cooling water. Several plants in East Texas had to ship in cooling water from other rivers in order to continue operation. If the drought had persisted another year, power cuts as large as thousands of megawatts may have been necessary (Averyt, et al., 2011).

Additionally, there have been a number of cases across the US, but especially in the West, in which proposed thermoelectric power plants were opposed by local stakeholder or were not approved due to water conflicts or concerns over water availability (Cooley et al, 2011).

Mitigation Strategies in Response to Drought

Harto & Yan (2011) surveyed state and local drought plans from California, Arizona, Colorado, New Mexico, Idaho, Montana, and Wyoming to determine the preparedness of Western states to water shortfalls. While most of these plans did not directly address electricity generation, they outlined drought response options and mitigation strategies including monitoring, modeling, and planning. Regions that take a more proactive approach to managing their water supplies are likely to have more water available for electricity production in the event of a drought.

Harto & Yan (2011) also conducted interviews on drought plans with representatives from utilities and government agencies responsible for water and electricity management. The primary response strategy cited was buying electricity from the market, though they expressed concerns over the cost of doing so. Little consideration was given to the fact that the availability of power is subject to drought conditions in neighboring regions as well as transmission capacity between producers. In addition to power purchases, interviewees identified 12 strategies for mitigating impacts. These strategies fall into four general categories: electricity supply, electricity demand response, alternative water supplies, and water demand response.

Virtual Water

Virtual water is the quantity of water embedded in another product. It represents the water consumed in the production of that product, and is similar to other embedded quantity concepts such as total energy requirements or carbon footprints (Lenzen, 2009).

The concept of virtual water was initially applied to food products traded into and out of the water scarce Middle East, but quickly expanded to other commodities (Allan, 2003). Recognizing the virtual water content of traded goods is helpful in understanding how certain regions (generally industrialized and urbanized) rely on water located in other regions for the products they consume, and that trade in water intensive commodities can act as a substitute for supply of or trade in the water itself. Virtual water trade networks can also show dependencies between river basins whereby consumers who obtain critical goods from neighboring or distant water basins are vulnerable to drought in those basins (Adams et al, in review). In this way, relying on virtual water can either mitigate or create risk for the electrical supplies of a state.

Trade of electricity can be thought of as trade in virtual water – especially during drought. When a water short region is unable to produce adequate electricity to meet its demand and purchases electricity on the spot market from a water rich region, water is embedded in the transfer. High electricity prices during these exchanges are partially a result of the value of water embedded in the electrical flow.

Yet, economic decisions unrelated to water availability primarily drive virtual water trade (Kumar & Singh, 2005; Hoekstra & Mekonnen, 2012; Porkka, Kummu, Siebert, & Floerke, 2012). Adams et al (in review) use an embedded resource accounting framework to show that water is currently not a critical factor in electricity production decisions. In their virtual water analysis of the Western US, they find that virtual water primarily flows from water limited states such as AZ, NM, NV, and UT to CA. A full third of the water used by these states for electricity production is thusly exported. The authors conclude that this shifting of water use for electricity production to states that are already water limited is an inefficient allocation of water resources, which may intensify future water shortages in the Western US.

Vulnerability Studies

Yan et al (2013) perform a drought vulnerability study for the Electric Reliability Council of Texas (ERCOT) to determine the risk of electricity disruption due to water shortages. The authors gather data on water availability, water demand, and water costs at the 8-digit hydrological unit code (HUC8) basin level. Water availability for thermoelectric cooling is determined by using meteorological data and water demands (from which evapotranspiration, stream flow, and water storage is estimated). Three drought scenarios are tested: (1) the recent drought of 2011, (2) a single year drought in 2022, and (3) a multiyear drought modeled after the drought of 1950-1957. The analysis identified (1) which reservoirs and HUC8 basins are vulnerable to water shortages during the drought scenarios, (2) that of the nine power plants available for an intake level study, all nine would be able to take in cooling water in drought scenarios, (3) that thermoelectric power production would need to be limited (i.e. reduced capacity factors) under drought conditions in order to avoid exceeding EPA mandated temperature limits to effluent discharge.

Ackerman & Fisher (2013) construct a model of the long-run energy supply and demand in the Western United States. The model projects energy demand via estimates of population growth, per capita electricity use, and temperature changes. They project their model into 2100. Generation mixes are pre-determined by scenario (business as usual, water saving, carbon saving, and water and carbon saving) and are assumed to persist to 2100. These choices are not made on a least-cost basis. Results show that their water saving scenario is only cost saving when water prices reach a value of $4000 per acre-foot – extraordinarily high. From this result, the authors conclude that water price (and therefore water availability) is unlikely to affect energy policy in the Western US. However, their model does not include the effects of drought on grid mix or as a constraint on total electricity production.

Harto & Yan (2011) use a simple, first-order model to analyze the risk to electricity production from drought in each of eight hydrological basins in the Western US and Texas. The authors develop three drought scenarios based on a survey of historic drought patterns. The three drought scenarios modeled are (1) west-wide drought, based on the 1977 drought during which five of eight basins experienced severe drought, (2) defined by selecting conditions representing the 10th-percentile drought year for each basin, (3) low-flow hydro defined by WECC. According to their analysis, electricity production shows resilience to interruption due to drought in the majority of basins. The Pacific Northwest, however, is vulnerable to drought due to its dependence on hydropower, and Texas is vulnerable due to its dependence on surface water for thermoelectric cooling.

Sovacool & Sovacool (2009) conduct a study to determine the locations in the US where the most severe water shortages due to withdrawals for thermoelectric power generation will occur. They identify 22 counties in 20 major metropolitan areas that are at risk for severe water shortages based on population growth estimates, utility estimates of future planned capacity additions, and estimates of the summer water deficit (the difference between water supply and demand in July, August, and September). At risk counties in the Western US include Denver, CO, Multnomah, OR, Contra Costa, CA, and Clark, NV.

Kimmell & Veil (2009) estimate the impacts on thermoelectric generation capacity from a drop in surface water levels. To conduct their analysis, the researchers build a database of power plants and cooling water intake locations. Most of the power plants included in the database are from the Eastern US. Only 26 power plants from the Western US are analyzed. Examination of the database reveals the depth that water levels can drop before cooling water intakes no longer function. They find that the average intake depth for power plants that draw their cooling water from rivers and creeks to be approximately 13 ft below the normal water surface, while the average intake depth in lakes and reservoirs is 22 ft. Yet, 43% of the plants surveyed have intakes at depths of 10 ft or less, indicating that a large proportion of power plants are potentially vulnerable to low flows, and that disputes over cooling water for power plants located on the same water body could become contentious. They also review legal agreements, such as water rights, that give priority to certain users of the respective water sources in the event of a shortage.

Poch et al (2009) use the findings of the above study by Kimmell & Veil (2009) to quantify the impacts of surface water level drops on the generation mix, electricity prices, and CO_2 emissions in the Western US if utility operators were forced take affected power plants out of service or reduce their outputs. The authors model the WECC system dynamically for the years 2006-2020. Their model simulates the hourly loads in each of the four WECC regions, and then simulates the electricity generated by hydro and renewables. To determine thermal generation, they run a probabilistic dispatch model for each power plant based on a pre-determined grid mix. The authors anticipate that new capacity added to the WECC regions will largely consist of water efficient coal-fired power plants. Based on their load projections and grid mix, they determine hourly electricity prices in 2006-2020 for the baseline model run. To determine the effects of drought on their system, the authors first reduced the amount of available hydropower capacity. Then, they compare spatial data of drought conditions during January 27, 2009 to the power plant database compiled by Kimmell & Veil (2009) and shutdown or curtailed output from plants in drought regions. Results show an increase in CO_2 emissions and electricity prices due to drought. The model shows an increased use of natural gas plants to make up for the shortfall of hydro and coal power due to the drought.

Roy, Summers, Chung, & Radde (2003) conduct a county-level survey of present and future freshwater availability alongside generation demand throughout the US through 2025. Each region of the country is given a water supply index score based on water availability, water resources development, sustainable groundwater use, environmental constraints, projected growth in water demand and power generation, and growth in demand for stored water. Using this index, regions of the country where water sustainability is likely to become an important issue are identified. They find that water-induced constraints to electric power generation are not limited to the arid regions of the West and Southwest, but occur throughout the country. Population growth will likely put greater pressures on water availability in the future, and climate change may further exacerbate shortages.

Related Studies

Lall & Mays (1981) develop an optimization model of water-energy systems. The model has a nonlinear objective function and linear constraints, and includes the subsystems of water availability, electric power generation, and coal and natural gas extraction. The objective of the model is to minimize the total costs of meeting water, gas, coal, and electricity within a region in northeastern Texas. The authors find that the availability of water determines power plant siting, and inter-basin transfers of electricity from regions with high electrical demand but low water to ones with ample water resources but low electrical demand was common, implying a reliance on virtual water transfers. They conclude that the model is an improvement over planning water and energy systems separately.

Matsumoto & Mays (1983) create an optimization model for the capacity expansion of the water-energy system to investigate alternatives for water and energy resources development. The objective of the model is to minimize capacity, production and distribution costs while meeting demands, subject to resource limitations.

Palmer & Lund (1986) review the impacts of drought on electric power generation, in addition to factors that influence the susceptibility of utilities to drought They also review management strategies and operational objectives during drought. Finally, they develop a risk analysis strategy for drought and present a case study of its application.

Myhre (2002) conducts a screening study to determine the types of power plants that were the largest users of freshwater resources, and project water use by thermoelectric power generation into the future. Results suggest that the larger the shift from coal and nuclear generation to natural gas, the greater the decrease in water required for electric power generation.

Maulbetsch (2004) conducts case studies covering the range of climates throughout the US in order to assess the cost and effect on plant performance associated with dry cooling technologies in place of recirculating wet cooling. The author finds that a dry cooling system employed at a 500 MW combined-cycle power plant can save approximately 900 million gallons per year if used in place of a recirculating wet cooling system. At a 350 MW coal-fired plant, the savings are approximately two billion gallons per year. But dry cooling is likely three to five times more expensive than wet cooling, and on the higher end of this range for dry, arid climates like those of the West. The cost of water saved from implementing dry cooling ranges from $1,100-$14,00 per acre-foot ($3.50-$4.50 per thousand gallons of water).

Maneta et al (2009) create a high-resolution hydroeconomic model that feeds water availability results from a hydrodynamic model into an economic production function that simulates agricultural production. The model solves for the optimal economic scenario for agricultural production given the spatial and temporal distribution of water. The authors then simulates drought conditions on a river basin in Brazil and find that the economic impact on farmers depends on their location in the watershed and their access to groundwater.

Wu & Peng (2010) developed a data inventory and modeling tool to estimate the amount of water withdrawn and consumed for electric power production in the United States. The purpose of the tool is to allow decision makers to analyze tradeoffs among fuel types. They find that once-through cooling is the still the dominant user of water for power generation, followed by wet recirculation using cooling ponds. Natural gas combined cycle plants use the lowest amount of water by fuel source, and is thereby the most promising thermoelectric generation technology from a water conservation perspective.

The National Energy Technology Laboratory (2011) estimates future freshwater withdrawal and consumption requirements for US thermoelectric generation using regional projections from the EIA's Annual Energy Outlook 2011 report. Based on current regional grid mixes and needs for capacity expansions, they develop five scenarios for the types of generation that will be installed through 2035 (eg 90% of additions use freshwater for wet recirculating cooling, and 10% use saline water for once-through cooling). Results show that while total US generation will increase by approximately 83 GW by 2035, freshwater withdrawals will decrease by 2-24%, but freshwater consumption will increase by 10-28%. This is due to the projected replacement of plants with once-through cooling systems with ones with wet recirculating systems.

Cooley et al (2011) estimate the future water requirements for thermoelectric power in the Intermountain West, using EIA energy mix projections as a basis for their study. They anticipate that the majority of new power production over the next 20 years will come from natural gas. Average water withdrawals per unit of energy produced are expected to decline, but total withdrawals will increase by 2%. They also expect total water consumption to increase by 5% because of the addition of wet-recirculating power plants. Under a renewable energy-friendly scenario, energy efficiency and expansions of generation from wind and natural gas combined cycle plants reduce total water withdrawals and consumption by 50% and 30% respectively.

Lin et al (2012) develop a water-resource and electric-power systems planning model based on interval-parameter programming and mixed integer programming to aide water/energy planners in effectively allocating water among hydroelectric power production, industrial uses, agriculture, and municipalities. Their model accounts for water use by the different consumer types, as well as future grid expansion and resulting water use.

Tidwell et al (2012) investigate the potential impact of water availability on future thermoelectric capacity expansion. They estimate the extent and location of water shortages due to thermoelectric development based on different scenarios for the projected future fuel mix. Their yearly time-step based model is organized according to the five interacting systems of demographics, electric power production, thermoelectric water demand, non-thermoelectric water demand, and water supply. They project that by 2035, under baseline energy mix projections, total water withdrawals from thermoelectric power production will decrease 2% due to once-through plants being retired, while total water consumption from thermoelectric power plants will increase 39%. This increase represents 19% of projected total growth in water consumption. Significant portions of the West, Southwest, Florida, and The Great Plains were identified as having limited water available for future capacity development. Additionally, 19% of all thermoelectric production is likely to be located in ground or surface water basins with limited water availability.

Logar & van den Bergh (2013) review existing methods for determining the economic costs of drought – both damage costs and costs of mitigation and adaptation strategies. They find that there is no standard terminology, categorization, or method of determining drought costs in the literature. They conclude with the recommendation that planners considering among mitigation strategies conduct cost-benefit analyses in which the damage costs of potential droughts (factoring in drought probabilities) are compared to the costs of the mitigation and adoption strategies.

Davies, Kyle, & Edmonds (2013) use an integrated energy, agriculture, and climate change model to estimate the water use for thermoelectric power generation in 14 geopolitical regions. They then project their model into the year 2095 in order to assess the uncertainty surrounding future water use in the electric sector. Because of gradual replacement of once-through cooling systems for recirculating cooling systems, they estimate that global water withdrawals for electric power will decrease by 2095, despite increased generation, but total water consumption will increase.

METHODS

Overview

In line with the stated preferences of utility operators, the goal is to build an electrical grid that is resilient to disruptions due to drought, but at a reasonable cost (Palmer & Lund, 1986). The model is built such that, regardless of the severity of the drought, demand for consumers is met. Adaptation to drought is necessarily built into the outcome of the model. For utility owners, this grid configuration must also be profitable, otherwise it is unrealistic. Therefore, the objective is to maximize profit to utilities while meeting demand given a water constraint.

In the model, each of the 11 states within WECC is treated as a single unit for water availability, electricity price, electricity demand, and generation decisions. This level of aggregation is justified because water rights and management, as well as electricity prices are administered at the state level. State aggregation is also appropriate because this analysis is concerned with inter-regional and inter-basin electricity and water transfers. Data limitations on utility-scale generation and intra-state power transfers also necessitated this scale for the study.

This aggregation necessarily ignores geographic differences in electricity pricing, grid mix, water availability, and transmission capacity. In the model, each state chooses its highest profit generation mix to satisfy in-state demand, given a local water constraint. The model performs a steady-state, yearly analysis. Yearly demand is met by producing an average electricity mix, taking into account each generation type's capacity factor. Demand fluctuations during seasons and over the course of individual days are not accounted for.

States generate electricity and sell it to internal users or export it to the grid. For each generation option, profits from in-state use are in-state electricity price less levelized capital and operation costs. Profits from exports are the grid price less levelized capital and operation costs. Because in-state electricity prices are determined through political consensus, the assumption is that they remain constant regardless of drought or demand pressure. In-state electricity prices come from EIA data from 2011 (U.S. Energy Information Administration, 2012). Retail electricity prices are used rather than wholesale prices. The price on the grid is determined by a partial equilibrium economic model.

Table 1

State Electricity Prices - Retail

State	avg price (¢/kWh)
AZ	9.71
CA	13.24
CO	9.39
ID	6.46
MT	9.11
NM	8.74
NV	9.12
OR	8.11
UT	7.13
WA	6.83
WY	6.58

Generation Options

Generation mixes within each state are aggregated according to the following categories: coal, natural gas single cycle, natural gas combined cycle (NGCC), nuclear, biomass, geothermal, hydroelectric, solar PV, and wind. Within each of the 11 states, each option has an associated capacity, capacity factor, average cost, and average water use factor. Because this is a steady-state model, all generation profiles have been smoothed into average capacity factors. PV and wind, for instance, merely operate during a fraction of the analysis period proportional to their average capacity factor.

Each state can deploy existing capacity up to current limits. Data for capacity of existing plants comes from U.S. Energy Information Administration (2013) while data for their water use comes from Averyt et al (2013). Average yearly capacity from the existing grid mix is shown below.

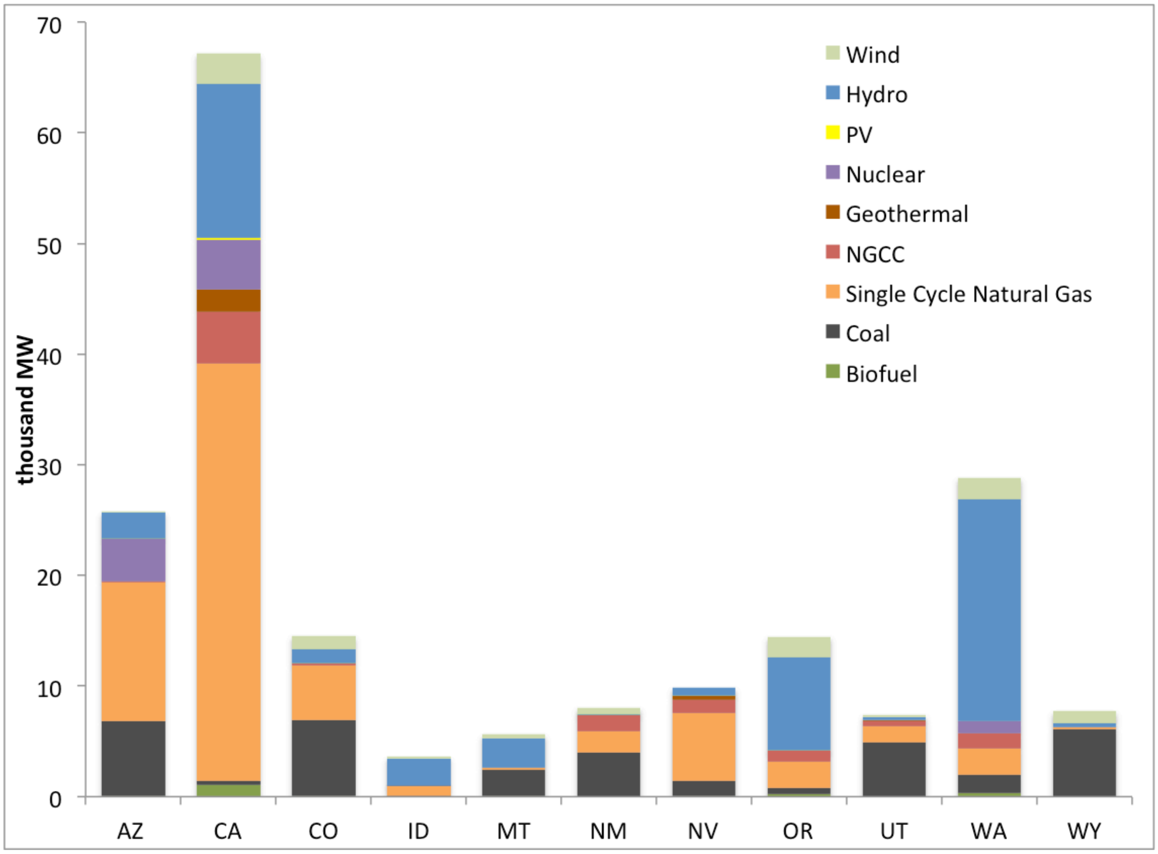


Figure 5. *Current Electricity Capacity Mix by State. Note large amounts of hydro in CA, OR and WA. Single cycle natural gas plants are primarily used to meet peak loads. NGCC is currently uncommon in many states.*

Levelized capital costs, total adjusted costs, as well as variable and fixed operating costs for power plants are based on EIA projections for 2018, and are unique to each of the four WECC sub-regions (U.S. Energy Information Administration, 2013). Costs are levelized over 30 years (the typically assumed life of energy infrastructure) using a 8.6% discount rate (U.S. Energy Information Administration, 2013).

Table 2

Levelized Costs of Installation and Generation by Energy Type and NERC Region

Plant Type	Cost ($/MWh)	NERC Region AZNM	CAMX	NWPP	RAMP
Coal	Fixed O&M	4.11	-	4.11	4.11
	Variable/Fuel	25.64	-	27.53	25.64
	Total Adjusted Levelized Capital	87.53	-	90.26	86.91
Natural Gas Combined Cycle	Fixed O&M	1.7	1.98	1.7	1.7
	Variable/Fuel	48.6	52.56	47.76	48.6
	Total Adjusted Levelized Capital	67.92	76.14	66.04	68
Natural Gas Single Cycle	Fixed O&M	2.63	2.63	2.63	2.63
	Variable/Fuel	68.13	76.62	54.14	68.13
	Total Adjusted Levelized Capital	107.23	119.04	90.31	108.64
Nuclear	Fixed O&M	11.62	-	11.62	11.62
	Variable/Fuel	12.3	-	12.3	12.3
	Total Adjusted Levelized Capital	98.45	-	98.95	98.78
Biomass	Fixed O&M	14.27	14.27	14.27	14.27
	Variable/Fuel	49.73	42.33	42.33	49.73
	Total Adjusted Levelized Capital	118.24	115.21	111.05	116.81
Geothermal	Fixed O&M	10.14	12.63	13.33	-
	Variable/Fuel	0	0	0	0
	Total Adjusted Levelized Capital	91.44	79.89	74.69	-
Pond Hydro	Fixed O&M	4.22	3.24	3.45	4.11
	Variable/Fuel	9.05	7.16	4.02	11.21
Wind	Fixed O&M	11.47	12.9	11.47	11.47
	Variable/Fuel	0	0	0	0
	Total Adjusted Levelized Capital	81.56	90.58	82.38	81.43
Solar PV	Fixed O&M	7.61	7.82	9	8.49
	Variable/Fuel	0	0	0	0
	Total Adjusted Levelized Capital	102.37	116.56	120.67	108.17

A key assumption in the model is that states have already built a drought adaptive grid mix when drought hits. All capacity is built up front and investments are uniformly levelized. New capacity can be built in any of the above categories except hydro, as the suitable rivers in the Western US are fully utilized. New power plants are assumed to be built with water efficient recirculated cooling systems, based on the Clean Water Act §316 Phase 1 rule that effectively requires all new thermoelectric power plants to install recirculating cooling systems due to standards for water intake capacity and velocity (Feeley et al, 2005). New power plants are also assumed to operate at capacity factors comparable to previously existing plants of the same type within the state.

Low risk vs at risk. Based on previous data analysis done by NREL, existing thermoelectric power plants within WECC are classified as either 'at risk' to drought or 'low risk' for drought. 'Low risk' plants either require no water for cooling (eg, PV, wind, and natural gas combustion turbine) or use an already secured non surface water source (eg, groundwater wells, ocean water, reclaimed wastewater). All plants using a surface or unstated water source were assumed to be at risk to drought (Harto & Yan, 2011).

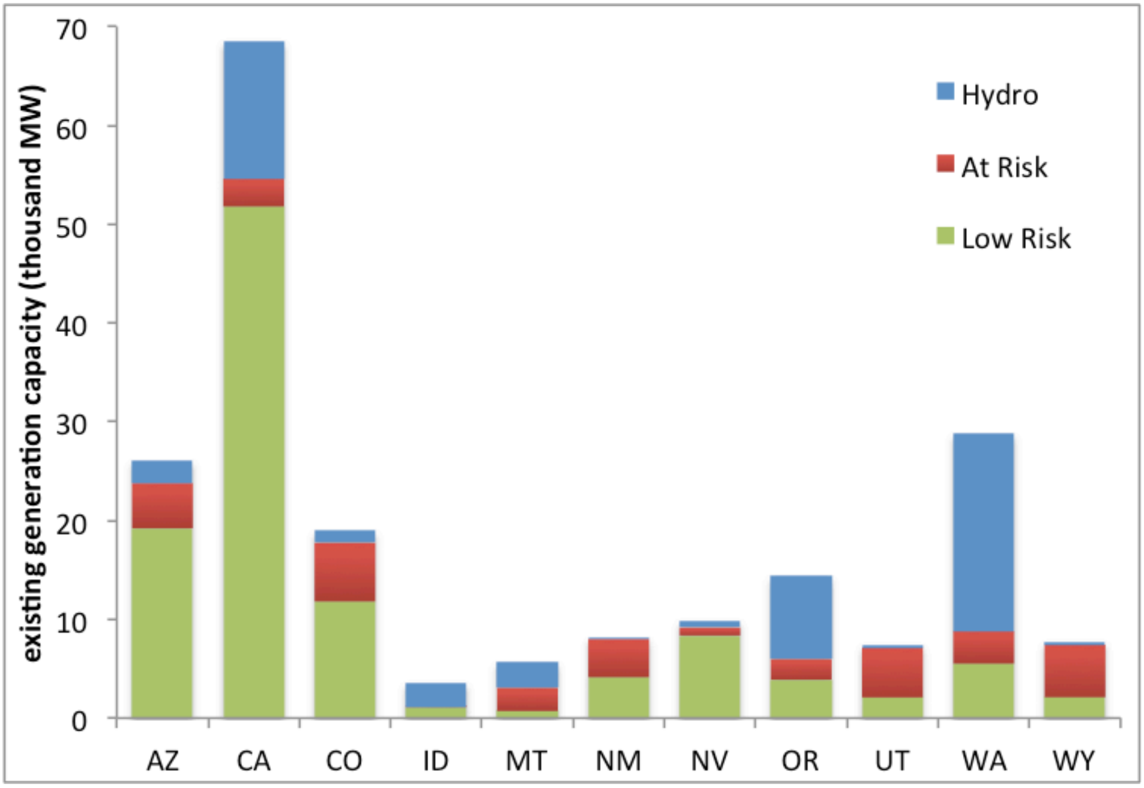


Figure 6. *Risk Factors for Capacity in Western States.*

For a capital outlay, 'at risk' plants can be retrofitted with more efficient cooling technologies, significantly lowering water consumption for the chosen amount of capacity. The assumption is that when a plant retrofits, a dry recirculating cooling system is installed. Below is a table containing the average levelized price increase per kWh generated with a new dry cooling system for five types of power generation (Tidwell et al, in review).

Table 3

Avg Cost of Dry Cooling Retrofits by Energy Type

Plant Type	Additional levelized cost of generation from retrofit (¢/kWh)
Biomass	0.33
Coal	0.31
Geothermal	0.19
Natural Gas	0.60
Nuclear	0.24

Water Source Alternatives

According the data defined above, each type of plant has a water use factor based on the weighted average of water use by plants of that type within each state. Water use factors are based on the water consumed by power plants rather than water withdrawn. This assumption ignores the thermal impacts of once-through cooling systems on local watersheds, which are the most common cause of capacity reduction for thermoelectric generation. This assumption is consistent with Ackerman & Fisher (2013) who acknowledge that once-through systems are more common in the Eastern United States where water is more abundant. Because they require higher withdrawal rates, these systems are being phased out of the Western United States. Power generation in Texas, on the other hand, is vulnerable to these considerations (Yan et al, 2013).

Using the inventory of water use, capacity, and capacity factors for all ‘at risk’ thermoelectric plants, the amount of surface water typically consumed by the ‘at risk’ plants in each state during a year is calculated. This value is the total surface water available for consumption by ‘at risk’ thermoelectric power plants in a normal year. When the model allocates generation to an ‘at risk’ plant, the water used comes from this pool. Using the water in this surface water pool is effectively free for power generators. This represents the sunk cost for infrastructure previously installed to access this water.

The model also allows for plants to be retrofitted to accommodate alternative sources of cooling water, such as treated wastewater effluent or brackish groundwater. Oftentimes this water must undergo additional treatment in order to used in the plant, either to prevent fouling of plant equipment or to comply with water and air quality regulations. Additionally, the physical layout of power plants may need to be changed in order to properly intake water from alternative sources (U.S. Government Accountability Office, 2012).

In additional to the surface water normally available to ‘at risk’ power plants, the model may chose to cool thermoelectric power plants with these additional types of water – for an additional cost:

- Unappropriated surface water – this designation is very rare in the Western United States, as most existing surface water has already been allocated to some user or another. Still, there is some unappropriated surface water available in the Pacific Northwest.
- Agriculture – water that has been previously allocated to low-value agriculture, from which the water rights may be purchased. Prices for water temporarily leased from agriculture were considered, but the prices greatly fluctuated due to situational factors. The purchased prices used here are lower and more consistent. But using purchase prices assumes that farmers would be willing to permanently shut down operation in exchange for lucrative water rights, a practice already

occurring in California despite local backlash (Jain-Cocks, 2010). The economic losses from decommissioning agriculture are not accounted for in the model.

- Wastewater – effluent from wastewater treatment plants that can be purchased in the way that the Palo Verde nuclear facility in Phoenix, AZ purchases wastewater from the 91st Ave wastewater treatment plant. Approximately 50 US power plants already use wastewater effluent as cooling water, and its use has become more common in recent years. Demand for this water has therefore risen, and its cost has gone up (U.S. Government Accountability Office, 2009).
- Potable groundwater – unappropriated potable groundwater can be obtained for pumping and treatment costs. In some states (such as Arizona and Nevada), state-issued permits are required to withdraw groundwater (U.S. Government Accountability Office, 2009). In California, this water cannot be used for thermoelectric power development.
- Brackish groundwater – is less saline than seawater, but is sufficiently salty to require heavy treatment in order to be potable. This is the most expensive type of water available to power plants. When its cost is greater than $3/1,000 gal, it is more economical for utilities to retrofit plants with dry cooling (Yan et al, 2013)

The costs and availability of the five types of water in all eleven states are provided by the authors of Yan et al (2013). The data projects over the next 30 years, and is in the table below. The costs include conveyance and treatment. Water commitments have been included. For example, Arizona currently has agricultural water available, but has future water commitments planned such that, in 30 years, it will already have been allocated.

Table 4.

Water Cost and Availability by State and Water Source

State	Surface Water for At Risk Plants	Unappropriated Water	Agriculture Water		Potable Groundwater		Reclaimed Wastewater		Brackish Groundwater	
	bil gal / yr	bil gal / yr	bil gal / yr	$ / 1000 gal	bil gal / yr	$ / 1000 gal	bil gal / yr	$ / 1000 gal	bil gal / yr	$ / 1000 gal
AZ	12	0	0	0.04	0	0.19	0	0.25	116	2.46
CA	27	0	0	0.06	0	0	261	3.27	0	2.46
CO	13	0.003	138	0.23	3602	0.12	8	0.30	19	2.32
ID	0.02	0.15	22	0.02	9138	0.07	2	0.17	5	2.21
MT	8	0.10	13	0.02	9104	0.05	1	0.70	21	2.43
NM	7	0	0	0.11	234	0.13	19	0.34	4	2.38
NV	4	0	12	0.12	162	0.16	49	0.09	7	2.16
OR	0.84	0.03	0	0.01	12914	0.07	1	0.29	1	2.08
UT	17	0.000005	0	0.06	1127	0.43	0	0.10	31	2.34
WA	8	0.42	0	0.02	14630	0.04	14	0.52	5	2.03
WY	13	0.03	0	0.03	2810	0.12	9	0.95	78	2.38

Electricity Trading (Virtual Water)

States can choose to export electricity to or import electricity from the grid, but not both. Each unit of exported electricity is tied to a generation source and water type. The grid is treated as a unified, external arbiter of trade. The balance of electricity on the grid is always zero.

A partial equilibrium model (partial because the model only considers the market for electricity and no other aspects of the economy) determines the price of power on the grid (Zerbe & Bellas, 2006). Trades to and from the grid are mediated by a single price. The cost of an imported kWh is the same as the revenue from an exported kWh. Importers also pay an O&M cost of 0.5 $/MWh for transmission (Bonneville Power Administration, 2011). Based on an initial price of electricity on the grid, profit from electricity exports and electricity imports are determined. Using these initial prices, each state chooses either to export power to the grid or import power from the grid as a generation option. The model then recalibrates the grid price based on the supply and demand of power. Eg., if total exports are greater than total imports, the price of grid power is lowered. The process iterates until an equilibrium price is selected at which imported electricity equals exported electricity.

Each state has limited capacity to transmit and receive electricity from the grid. For each state, the sum of exports and imports cannot exceed this capacity. All transmission capacity data is aggregated on a per-state basis. Data for the maximum current transmission to and from each state in shown in the table below (Stamber, Vugrin, Shirah, & Stampe, n.d.). This aggregation ignores in state transfers and local bottlenecks.

Many areas of the US have transmission corridors in which the lines are very close to capacity (Kimmell & Veil, 2009).

Table 5

Total External Transmission Capacities by State

State	Transmission Capacity to Grid (MW)
AZ	26590
CA	34644
CO	11719
ID	29736
MT	6460
NM	15010
NV	25661
OR	52389
UT	12154
WA	42771
WY	15368

Importers can choose to expand their transmission capacities at an increased cost. Assuming that the average distance between states is 300 miles, the price of a new 230 kV transmission line (capable of transmitting 400 MW) is $1.6 million, and the lines are used at an average capacity of 50%, the levelized cost of new transmission capacity is ~$20/MWh (West Virginia University, 1998; Patterson, n.d.; Ng, 2009; Bonneville Power Administration, 2011).

Structure of the Model

To simulate the behavior of utility operators during drought conditions, the objective of the model is to maximize profits from power generation over the year time-frame subject to capacity and water constraints. Each state acts independently. For each state, the objective function is therefore:

$$\max_{C_i} \sum_{i=1}^{N} 8760 C_i F_i \Pi_i \tag{1}$$

Where C_i is the selected capacity to be used for each generation option i (in kW), F_i is the capacity factor for each generation option i (%), and Π_i is the profit for each generation option i ($/kWh). Profit for in-state generation is in-state electricity price less levelized capital and O&M costs. Profit for exported generation is grid price less levelized capital and O&M costs. Profit for imports is in-state price less grid price less transmission costs. N is the total number of generation options. There are 8760 hours in a year. The objective function is subject to three constraints:

$$\sum_{i}^{J_j} C_i \leq C_{0j} \tag{2}$$

$$\sum_{i}^{N} 8760 C_i F_i = D \tag{3}$$

$$\sum_{i}^{K_k} 8760 C_i F_i U_i \leq W_k \tag{4}$$

Where C_{0j} is the initial capacity (in kW) of generation type j (eg, coal), J_j is the total number of options that share the capacity of type j (eg, in-state coal generation and coal generation for export share the same capacity), D is yearly in-state electricity demand (kWh), U_i is the water consumption of each generation option i (gal/kWh), W_k is the total water available for water type k (gal/year), and K_k is the total number of options that share water type k (eg, coal using reclaimed water, natural gas using reclaimed water).

For each state, the model solves for C_i using the Lagrangian multiplier linear programming method for constrained optimization (Bertsekas, 1996). Imports are balanced with exports using the process described in the section above.

Modeling of Drought

Intensity. Because surface water represents the majority of water utilized for electric power production, a drought intensity factor is defined from 0 to 1 equal to the stream flow deficit. This follows the precedent established by Harto & Yan (2011) who claim that "stream-flow deficit during drought events reflects an overall system response to drought impacts" in their analysis of drought effects on electricity production. Based on a previous analysis by WECC (Pacini, 2012), it is assumed that the normal flow of surface water available would begin to shrink when the drought factor becomes greater than 0.5, such that:

$$Available\ Water = \begin{cases} Normally\ Available\ Water, & Drought\ Factor < 0.5 \\ Normally\ Available\ Water \times 2(1 - Drought\ Factor), & Drought\ Factor \geq 0.5 \end{cases} \quad (5)$$

In this way, only when streamflow is halved (an indication of an extreme drought) does the surface water available for thermoelectric power begin to be reduced. This estimation represents a number of possible scenarios that could occur during a drought: (1) water levels falling below cooling-water intake structures, (2) water levels dropping past a certain threshold in lakes and reservoirs that triggers authorities to curtail withdrawals, even if the water levels are above intake structures, (3) high temperature surface waters being ineffective coolants, or (4) low water levels and high temperatures causing cooling-water discharge temperatures to exceed permitted limits, triggering curtailments to generation (Harto & Yan, 2011).

For hydroelectric generation, it is assumed that generation is proportional to surface water flow in the basin. This assumption is corroborated by the work of Harto & Yan (2011), who found that, for most basins in the West, the fit between flow and generation had R^2 values great than 0.7 (Pacific Northwest, California, and Upper

Colorado). Basins with higher reservoir storage capacity relative to flow, such as the Lower Colorado, are better able to buffer against yearly changes in flow (Bureau of Reclamation, 2012). This assumption likely over-represents the loss of hydro generation during drought.

For each hydro generation plant, available capacity during a drought is represented by:

$$Capacity = Avg\ Capcity \times (1 - Drought\ Factor) \tag{6}$$

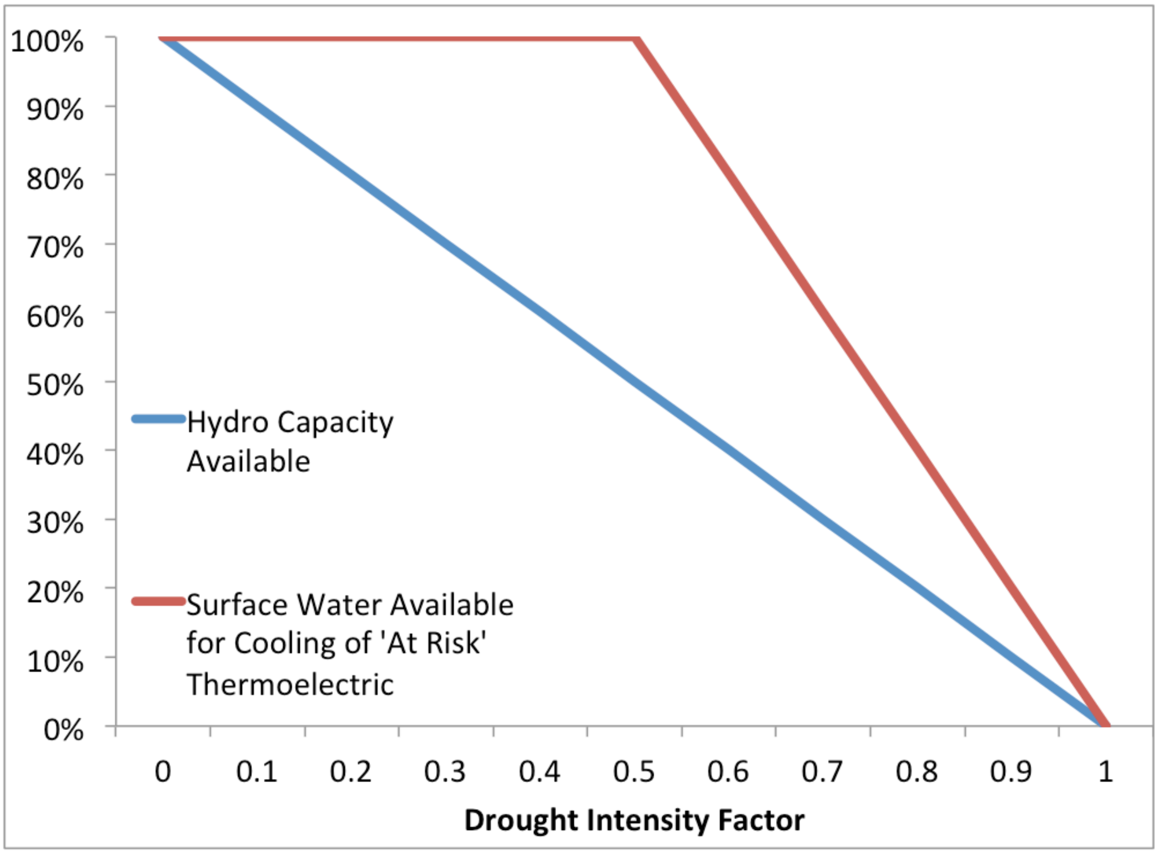


Figure 7. *The effect of drought intensity factor on hydro capacity and surface water for 'at risk' thermoelectric cooling.*

Duration. One run of the model simulates a year of power production. During this time, a drought of a given intensity occurs. The duration of the drought is apportioned to some fraction of the year, defined by the duration factor (between 0 and 1). For example, most droughts occur in the summer months. If it were to assumed that a drought occurs during the entire summer (3 months), the duration factor would be 0.25.

Duration is handled by running the model (at the drought intensity given by the scenario) first with an assumed duration of 0 (no drought) and then with a duration of 1. A weighted average determined by the duration factor is then applied to the results.

The model assumes that all investments are made upfront, in anticipation of a potential drought. In this way, the specific time period in which the drought occurs is not important. Only the duration and intensity matter. Yet, the weighted average method ignores the increase in levelized capital costs that result from utilizing energy infrastructure at lower capacity factors. In the model, the cost data for new capital infrastructure is levelized over a 30-year period, assuming industry average capacity factors (U.S. Energy Information Administration, 2013). If a certain piece of infrastructure is installed for the sole purpose of compensating for lost power production in the event of a drought, then that infrastructure will not be utilized under non-drought conditions, resulting in it operating below the capacity factor at which it was priced. The weighted average method accounts for this oversight by scaling back the amount of capital investment made in the drought-adaptation infrastructure by the proportion of time in which it is expected to be utilized (the drought duration factor). Even so, this method likely underrepresents the cost for building infrastructure intended to be utilized only under drought conditions.

Because it is assumed that investments are made upfront, the experience curve for new technologies (eg pv) is not accounted for, which would allow these generation options to grow less expensive over time and thereby become more attractive.

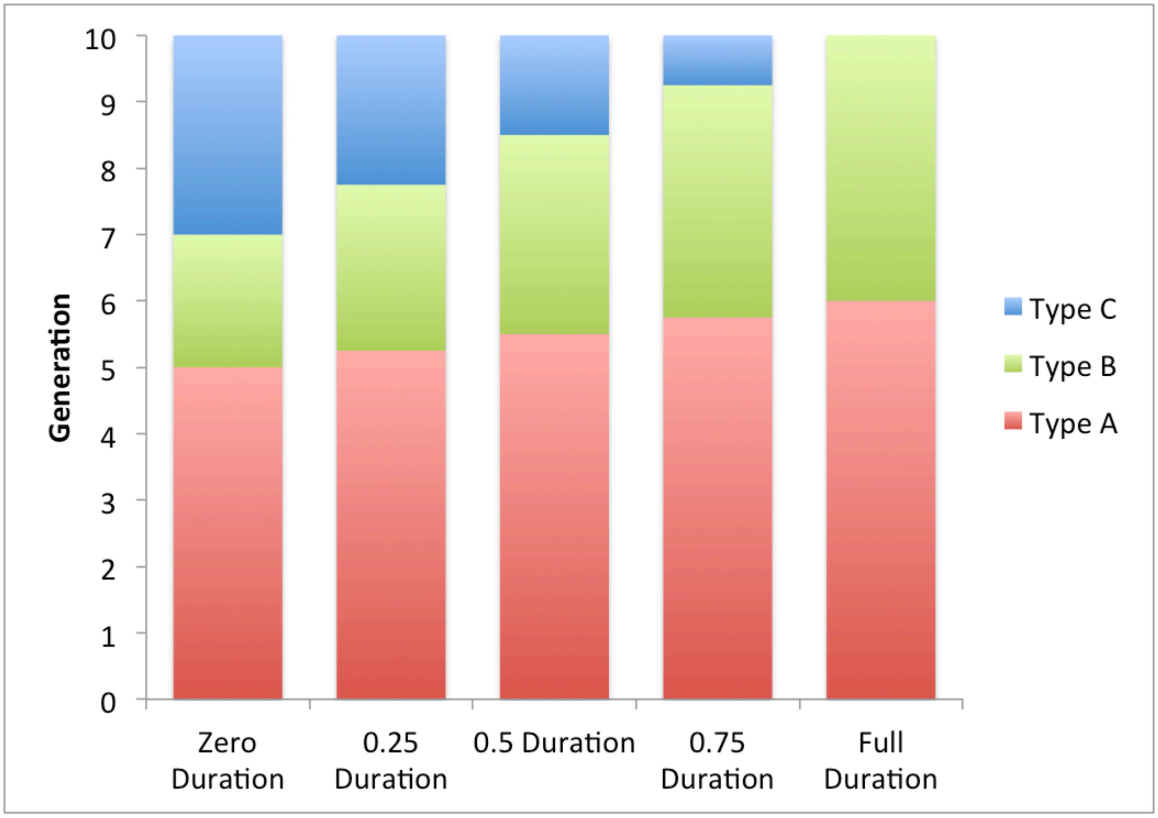


Figure 8. *The model's handling of drought duration for three dummy types of generation under some drought intensity. 0.25, 0.5, and 0.75 duration are weighted averages of zero and full duration. This figure is merely illustrative. No data was used in the production of this figure.*

Watersheds. Drought scenarios are applied to one or more states grouped by watersheds. Watersheds are defined using the two-digit hydrological united code (HUC-2) established by the US Geological Survey.

Figure 9. *HUC-2 Water Resource Regions in WECC (Harto & Yan, 2011).*

Visual inspection of the figure above allow California, Washington, Oregon, Idaho, and Arizona to be easily allocated to a basin. Because the majority of the population (and the majority of the power generation) in Nevada is in the southeastern corner, the state is considered to be in the Lower Colorado watershed. Most of the population of Utah lives in the Great Basin watershed. The population centers in New Mexico are in the Rio Grande watershed. Denver, and many other cities in Colorado, get their water from the Upper Colorado watershed. Though sparsely populated, the cities in Montana and Wyoming fall within the Missouri River watershed.

Table 6

Allocation of States to Watersheds

Watershed	States
Pacific Northwest	ID, OR, WA
California	CA
Great Basin	UT
Missouri	MT, WY
Upper Colorado	CO
Lower Colorado	AZ, NV
Rio Grande	NM

Dollar Intensity of Water

Following the method in Adams et al (in review), in-state and grid prices along with the average water embedded in each state's electricity production are used to calculate the dollar intensity of water for electric power generation. This value is derived from division of the price of electricity (in $/kWh) by the average water intensity of electricity (in gal/kWh). Again, water used for hydropower is excluded because it is not consumed, but rather passes through, the power generator. Dollar intensity is therefore a type of shadow price for water. A true calculation of shadow prices would require knowledge of the value of all inputs into electricity production, as well as the value added by turning those inputs into electricity. In the absence of this data, a simplified approach is taken that ignores these other factors. In order to compare this dollar intensity between states, it is critically assumed that all states value these other inputs equally.

Additionally, following the method outlined by (Konar, Dalin, Hanasaki, Rinaldo, & Rodriguez-Iturbe, 2012) and, later (Adams et al, in review), the water savings due to virtual water trade is also calculated for importing states.

Additional Assumptions

Demand response to temperature increases. There is no single standard method to measure change in the electricity demand in response to temperature increases (Harto & Yan, 2011). Each geographic region is likely to have a unique response based on saturation of air conditioners, insulation in the housing stock, socioeconomic conditions, etc. If temperatures increase uniformly during the year, increased cooling loads in the summer may be offset by decreased heating loads in the winter. Theoretically, some areas could see demand reductions.

Author estimates of change in demand as a function of temperature (conducted using a change point model with data from the Phoenix, AZ area) suggested a 2% increase in yearly electrical demand per 1 °C of temperature increase. Because temperatures during droughts only increase an average of 1 °C (Cayan, Das, Pierce, Barnett, Tyree, & Gershunov, 2010), the corresponding 2% increase in demand is ignored for this study, as it falls out of the uncertainty range for this analysis.

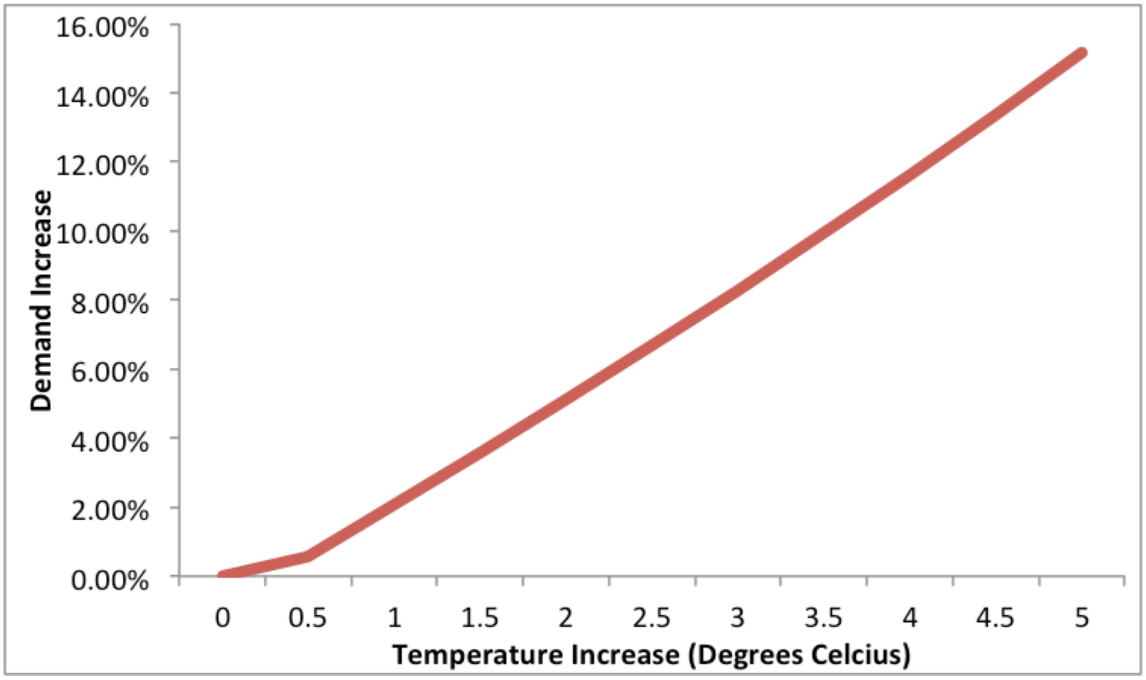


Figure 10. *Yearly Demand Increase as a Function of Temperature Increase for Phoenix, AZ.*

Additionally, although it is known that high temperatures cause decreased efficiency in power production, cooling water use, and electrical transmission, these factors were left out of the model (Sathaye, et al., 2012). The above assumption that drought typically causes a 1 °C increase in local temperatures suggests that drought alone would not result in a significant decrease in efficiency in these parameters, and so falls out of the uncertainty range for this analysis.

Scenarios

The purpose of the model is to identify a resilient grid mix to drought occurring anytime between the present and the not-so-distant future. As drought can occur in any year within this timespan, the high and low end of electricity demand changes are tested in the model: current electricity demands and 30-year EIA projected demands. Demands are in the table below.

Table 7

Current and Future Electricity Demands by State

State	Current Yearly Demand (MWh/year)	30 year Demand Projections (MWh/year)
AZ	74,935,850	108,656,983
CA	238,976,375	308,279,524
CO	53,232,053	75,589,515
ID	23,120,064	30,518,484
MT	11,131,135	14,693,098
NM	23,041,665	33,410,414
NV	32,417,516	47,005,398
OR	45,759,936	60,403,116
UT	28,858,946	38,093,809
WA	91,363,506	120,599,828
WY	17,417,762	24,733,222

First, the most extreme drought scenario is tested – droughts of maximum duration and intensity in all states. Although this scenario is unrealistic, as it represents zero stream flow in all rivers in the Western US, it is helpful to test the behavior of the model in such a situation. For this scenario, both current and 30-year demand factors are explored. These results are compared to no-drought scenarios for all states for both current and 30-year demand factors. These four cases represent the bounding scenarios of the model – from no drought to extreme drought, and from low demand to high demand. The table below shows the naming convention for these scenarios used henceforth in the text.

Table 8

Naming convention for bounding scenarios

Name	Drought	Demand
R0D0	No drought	Current demand
RXD0	Extreme drought: full intensity and duration	Current demand
R0D30	No drought	30 year demand
RXD30	Extreme drought: full intensity and duration	30 year demand

A scenario in which droughts are assigned to basins based on the locations of droughts in the historic record is also tested. In their survey of the literature on drought in the Western US, Harto & Yan (2011) identify that droughts occurring in the Pacific Northwest, California, and Great Basin tend to occur at similar times, but separate from droughts in the Rio Grande, Lower Colorado, Upper Colorado, and Missouri basins, which tend to occur together. In the first case of this scenario, a drought of varying intensity and duration is applied to the basins in the Northwest (Pacific Northwestern, California, and Great Basin), while the basins in the Southeast (Rio Grande, Lower and Upper Colorado, and Missouri) experience no drought. In the second case, the situation is reversed, with the Southeast basins experiencing drought and the Northwest basins not.

RESULTS

Results reveal the economically optimal configuration of the Western US electricity grid (including electricity trading) as it adapts to droughts and high demand.

Grid Mix

Current conditions – no drought, 2011 demands. An initial run of the model under no-drought, current electricity demand conditions reveals a strong bias towards low-cost generation options. Despite their availability, the model avoids generating electricity using single-cycle natural gas plants because of their high operational costs. In actuality, single-cycle natural gas plants make up a large proportion of total generation in AZ, CA, and NV. To make up the lost capacity, NV turns from a net exporter to a net importer and CA imports additional power. AZ has enough existing capacity to meet internal electricity demands, but not enough to export. Without AZ power available to meet CA energy loads, OR and WA find it economically beneficial to build natural gas combined cycle power to generate exports for CA.

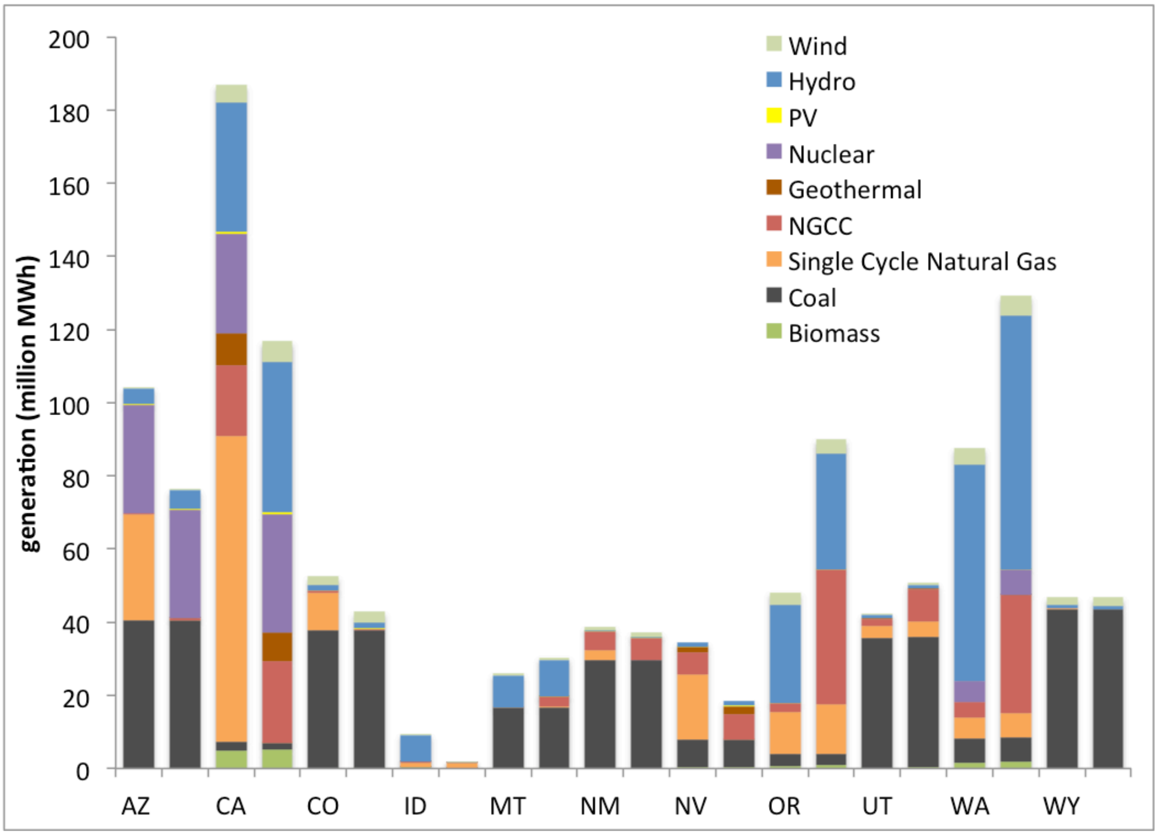


Figure 11. *Actual generation vs the generation selected by the model. For each state, actual generation is on the left while model solutions are the right. Note that, because single cycle natural gas plants are typically operated during peak loads and the model does not consider peaks, the model chooses not to utilize existing single cycle natural gas as they are too expensive to provide baseload power.*

While this behavior diverges considerably from the current pattern of electricity generation in the West, it makes sense in terms of the objectives and structure of the model. Single-cycle natural gas plants are inefficient and expensive to operate, but they are typically employed to accommodate load peaks. NGCC generators are a more recent technological development that, while considerably more efficient and less costly, have not yet taken the place of single-cycle plants. NGCC plants have a different role in power generation as they are increasingly used to provide baseload rather than peak power (U.S. Energy Information Administration, 2011). Because the steady-state model does not account for demand fluctuations during seasons and over the course of individual days, but rather calculates the average optimal mix strategy assuming a constant yearly demand, its inclination toward low-cost, baseload sources is justified. Although the model has largely excluded the use of single-cycle natural gas generators from its optimal mix, it is assumed they would be necessary to accommodate demands during peak load periods.

Response to demand growth – 2040 projections. In the no drought, 2040 demand projection scenario, the model accommodates demand increases by building new NGCC plants. NGCC is the most cost effective generation method for responding to demand growth. In this scenario, AZ, CA, CO, ID, and NV are the net importers, with OR, WA, and to some extent UT, providing the NGCC power for export. According to EIA data, the states of the Northwest Power Pool (ID, MT, NV, OR, UT, WA) can build NGCC plants more cheaply than states in other NERC regions. This partially explains why OR and WA build NGCC capacity in order to export. Another factor is that these states have relatively low in-state electricity prices relative to the model's calculated grid price ($0.066/kWh), which makes exporting power desirable. States with relatively high in-state prices, such as AZ, CA, CO, & NV, see greater returns from importing relatively inexpensive power and selling it for a higher price in-state. These price dynamics are the primary determinants of states' responses to demand increases. The retail prices used for the model likely overstate utility profits and understate costs for power production and regional transmission.

Growth of NGCC overstates, but is qualitatively consistent with the EIA's recent AEO report (U.S. Energy Information Administration, 2013), which anticipates that 63%

of new capacity installations over the next thirty years will be natural gas powered, with the majority as NGCC. The EIA also projects that renewables, which are unattractive in the model due to their high initial capital costs, are to represent 31% of new capacity. Because the model does not account for the possible future reduction of the relative price of renewable energy technologies through the experience curve or changes to fossil fuel prices and regulations, it possibly overstates the economic benefit of NGCC installation while overlooking renewables.

Response to drought. The extreme drought scenarios eliminate the option of generating hydropower, increasing the load that must be met from other sources. Other than hydro, no other generation types are negatively affected by surface water shortages because there is sufficient availability of other sources of water (agriculture, groundwater, etc) to provide for the water consumption of 'at risk' plants. States largely choose to tap into these more expensive water sources rather than retrofit existing plants with dry cooling systems. Even AZ, which only has brackish water to substitute for surface water, is able to meet the water consumption requirements of its large coal-fired fleet.

To make up the electricity shortfall due to absent hydro generation during drought, some states find it economically optimal to import power while others find it economically optimal to build new NGCC plants. This substitution of NGCC for hydro during drought is consistent with the findings of Poch et al (2009) and Wu & Peng (2010). Electricity price combined with the regional cost of new NGCC plants determines state behavior during drought. Those states with relatively high in-state electricity prices and high costs to build new NGCC (AZ, CA, CO, NV) choose to solely import to make up the shortfall. Those with relatively low costs to build new NGCC (MT, OR, UT, WA) choose to build NGCC for exports. NM and WY do no importing or building as they have relatively high costs to build new NGCC, virtually no hydro to lose during drought, and ample coal capacity to meet internal demand. Because of this dynamic, the grid price determined by the model (~$0.066/kWh, regardless of drought or demand) inevitably hovers around the cost for NWPP states to build new NGCC plants ($0.066/kWh).

Although transmission costs and constraints are built into the model, they may not capture some necessary details at the intrastate transmission scale, particularly the need for distant states to pass exported power through intermediary transmission corridors which do not have capacity to handle both pass-though and local transmission requirements. Because of its proximity to demand-heavy Southern CA, AZ is currently CA's largest supplier of electricity. The model, which calculates interstate electricity trade based on total flow rather than individual state-to-state connections, has OR and WA take the place of AZ. In reality, significant investments in transmission capacity between OR and Southern CA would be required before OR and WA overtook AZ as the major exporters to CA.

It should also be noted that, under drought and demand pressure, AZ transitions from being an exporter to being an importer. This occurs because of AZ's relatively high in-state electricity price, the relatively high price of natural gas in the AZ-NM region, and limited availability of low cost, alternative water sources. This result has implications for AZ and its neighbors, especially CA, but is contingent upon the capacity of local transmission corridors, as discussed above.

Note that the bounding scenarios represent extreme drought conditions. The most extreme droughts in the past hundred years within the Western US had intensity factors (according to the streamflow deficit scale defined above) between 0.28 (Upper Colorado watershed) and 0.66 (Pacific Northwest watershed) (Harto & Yan, 2011). Durations of actual drought are also likely to be far lower than the 100% level tested in the bounding scenarios. In order to capture a more realistic dynamic, in addition to the bounding scenarios, alterations to drought duration and intensity are tested. In these cases, the model produces a linear transition, scaling back hydropower in exchange for new NGCC in proportion to the intensity of the drought. Altering drought duration and intensity in equal proportion has a similar effect, suggesting that the model treats the economics of a short, intense drought similarly to a long, mild one of equal total hydropower deficit. As described in the methods section, geographic variability in droughts is also tested, with states in northwest basins being subject to drought while states in southeast basins are not, and vice versa. However, the model's response to these cases is the same as its response to the bounding scenarios. Even with drought in only the Northwest, the model finds it economical for OR and WA to build NGCC power for export. Thus, the model reveals no thresholds of demand increase or drought severity that trigger dramatic changes in the structure of the power grid. Regardless of the level of demand increase or the duration and intensity of the drought, the most cost effective generation method is NGCC.

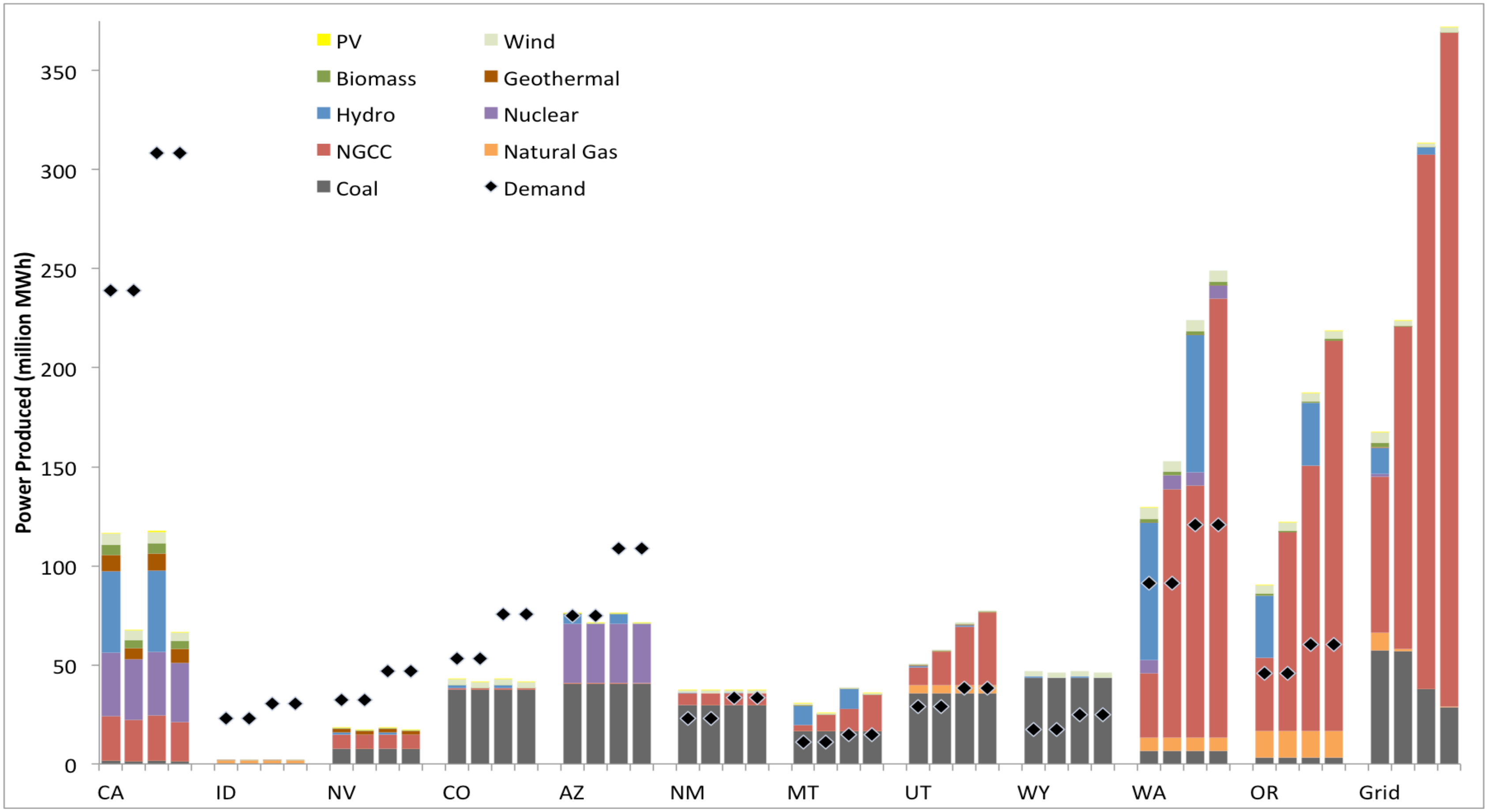


Figure 12. *Model solutions for generation mix in the bounding scenarios. States are listed in order from greatest importer to greatest exporter. For each state, scenarios are presented from left to right: R0D0, RXD0, R0D30, RXD30. During drought, NGCC plants installed in Northwest states are the most economically optimal substitute for lost hydropower. Also, as demands increase, NGCC installed in the Northwest is the most economical choice to meet much of the region's demand. Regardless of the level of demand increase or drought duration and severity, NGCC is always the most cost effective new generation method.*

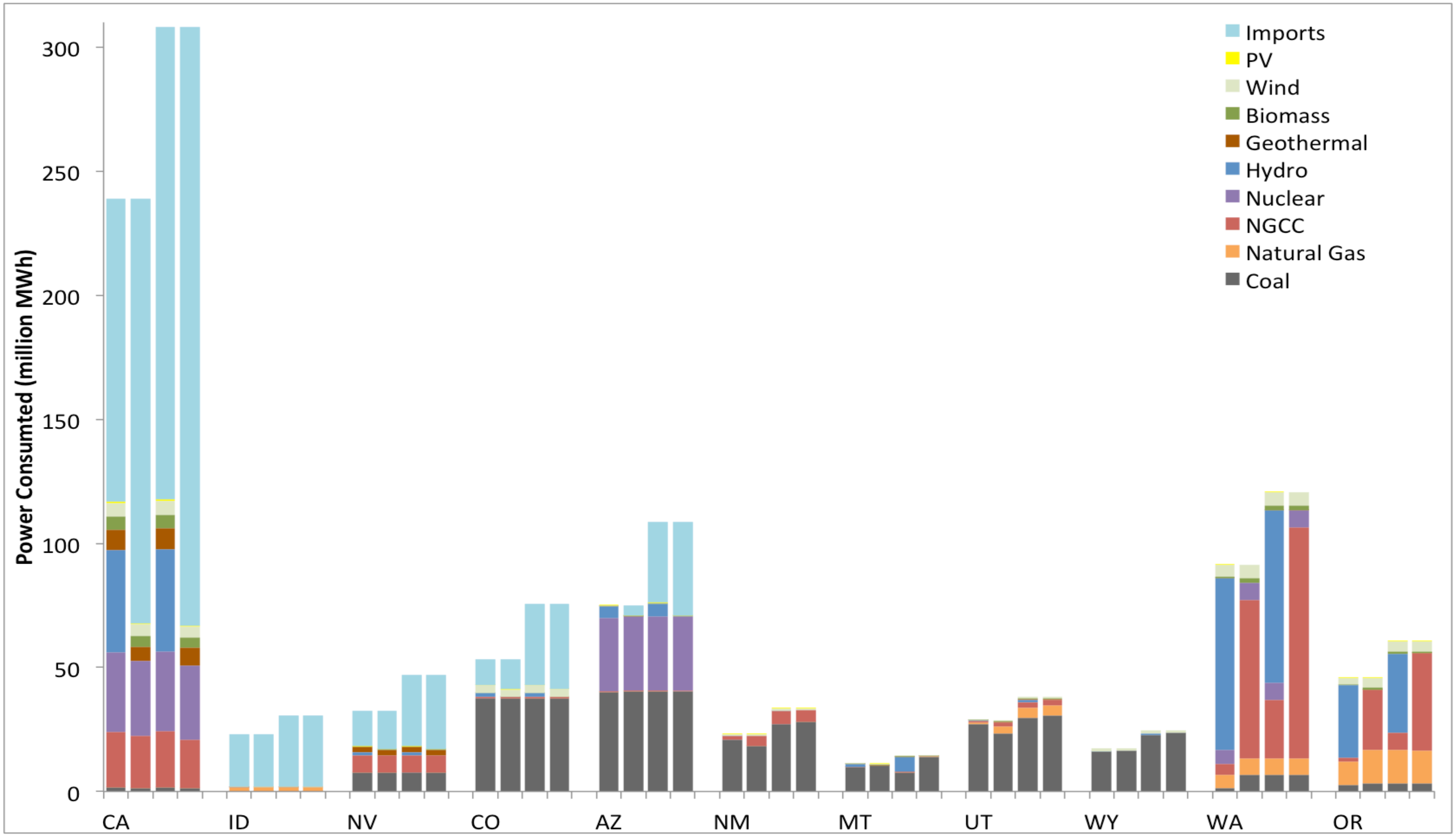


Figure 13. *Model solutions for consumption mix in the bounding scenarios. States are listed in order from greatest importer to greatest exporter. For each state, scenarios are presented from left to right: R0D0, RXD0, R0D30, RXD30. States that have relatively high in-state electricity prices (CA, AZ, NM, NV) respond to drought and demand increases by importing power. States that have relatively low costs to build new NGCC plants respond by building NGCC capacity for export.*

Virtual Water

NGCC power plants are highly water efficient compared with other thermoelectric generation technologies. When demand increases or drought eliminates hydropower and surface water for 'at-risk' plant cooling, states respond by building NGCC plants, and the average embedded water for power generation decreases.

Drought increases the average embedded water in power production used to meet in-state demand. This is due to hydropower being replaced with more water consumptive, locally sourced thermoelectric generation sources during drought. Note that, in the model, only water consumption is considered (rather than withdrawals), and hydropower is treated as consuming negligible amounts of water, following Scott & Pasqualetti (2010). Yet, during drought, exports (and likewise imports) become less water intensive because of the increased reliance on the new NGCC plants OR, UT, and WA use to export power to the grid. Results show average water intensity of power traded on the grid dropping 74% from the R0D0 scenario (no drought, current demand) to the RXD30 scenario (extreme drought, 2040 demand). As average water intensity of power traded on the grid decreases, total water savings due to trade increases. This result indicates the likelihood of effective and relatively affordable power system adaptation to drought both by net exporting states and by the power grid as a whole, due to the happy coincidence of the low-cost technology (NGCC) also being a low water technology.

Adams et al (in review) show that the water embedded in CA's locally produced power is lower, on average, than the water embedded in its imports. In reality, CA primarily imports from states with lower water efficiency such as AZ and NM. In the model however, CA primarily imports from OR and WA – the states with the most water efficient power production. Because of this dynamic, the modeled system is more adaptive to water limitations during drought than the real system; in the model, CA decreases its total water footprint for power consumption through import from OR and WA, whereas in reality (Adams et al, in review), CA increases its water footprint. It is likely that reality and the model will converge under future drought or demand scenarios, due to the underlying economics of generation.

Despite these differences, the model produces similar dollar intensity results to those of Adams et al (in review). As predicted, dollar intensity for water embedded in electric power production increases during drought and high demand scenarios. This trend is highly visible for imported power. States with the most water efficient electricity production have the highest dollar intensity for water, especially OR and WA, who primarily export highly water efficient NGCC power. Dollar intensity for in-state power, however, tends to decrease with drought. This is equivalent to observing that the value of water in a state is decreasing during drought – a counterintuitive result. This result is a coincidence of the model's accounting of hydropower as having no water consumption, and when it is not available during drought, the overall average embedded water for power rises, which decreases the dollar intensity of embedded water that is generated and consumed within the boundaries of a state. Recall that hydropower is primarily utilized within the state that generates it.

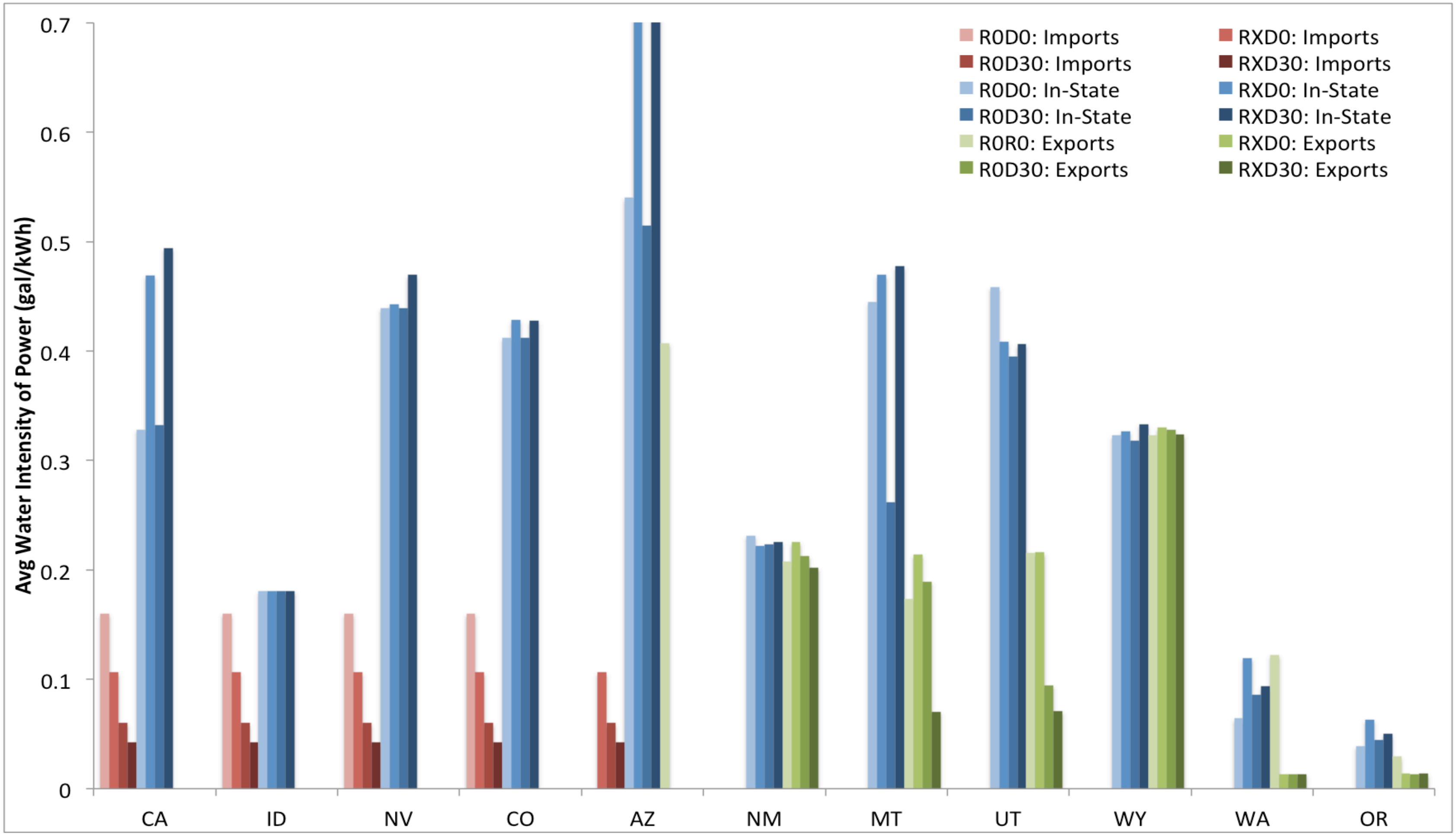


Figure 14. *Average embedded water for power generation for in-state production, imports, and exports in the bounding scenarios. Both 'at risk' and 'low risk' plants are included in the average. States are listed in order from greatest importer to greatest exporter. The embedded water on the grid decreases when drought or demand increases – by 74% from the R0D0 scenario to the RXD30 scenario. Embedded water for in-state production increases when drought or demand increases due to hydro power being replaced by water-consuming thermoelectric.*

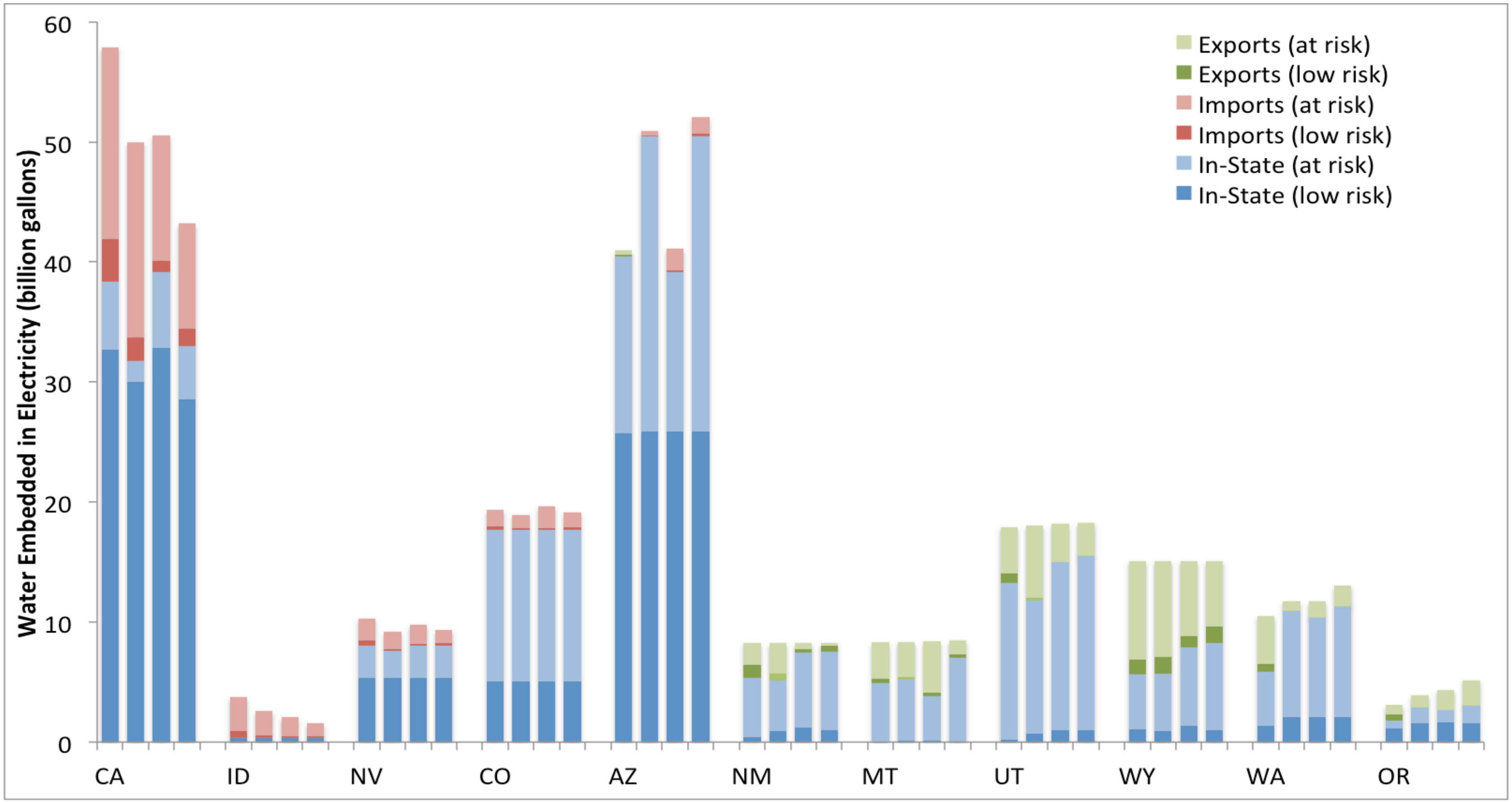


Figure 15. *Total embedded water for power generation for in-state production, imports, and exports in the bounding scenarios for both 'at risk' and 'low risk' power. States are listed in order from greatest importer to greatest exporter. For each state, scenarios are presented from left to right: R0D0, RXD0, R0D30, RXD30. AZ and CA utilize large amounts of 'low risk' water, primarily for coal and nuclear production. Despite their substantial exports, OR and WA use very little 'at risk' water because much of their production comes from water efficient NGCC plants. While the total water use of exporting states increases under drought and demand pressure, water efficiency increases (see the figure above), so importing states import less embedded water.*

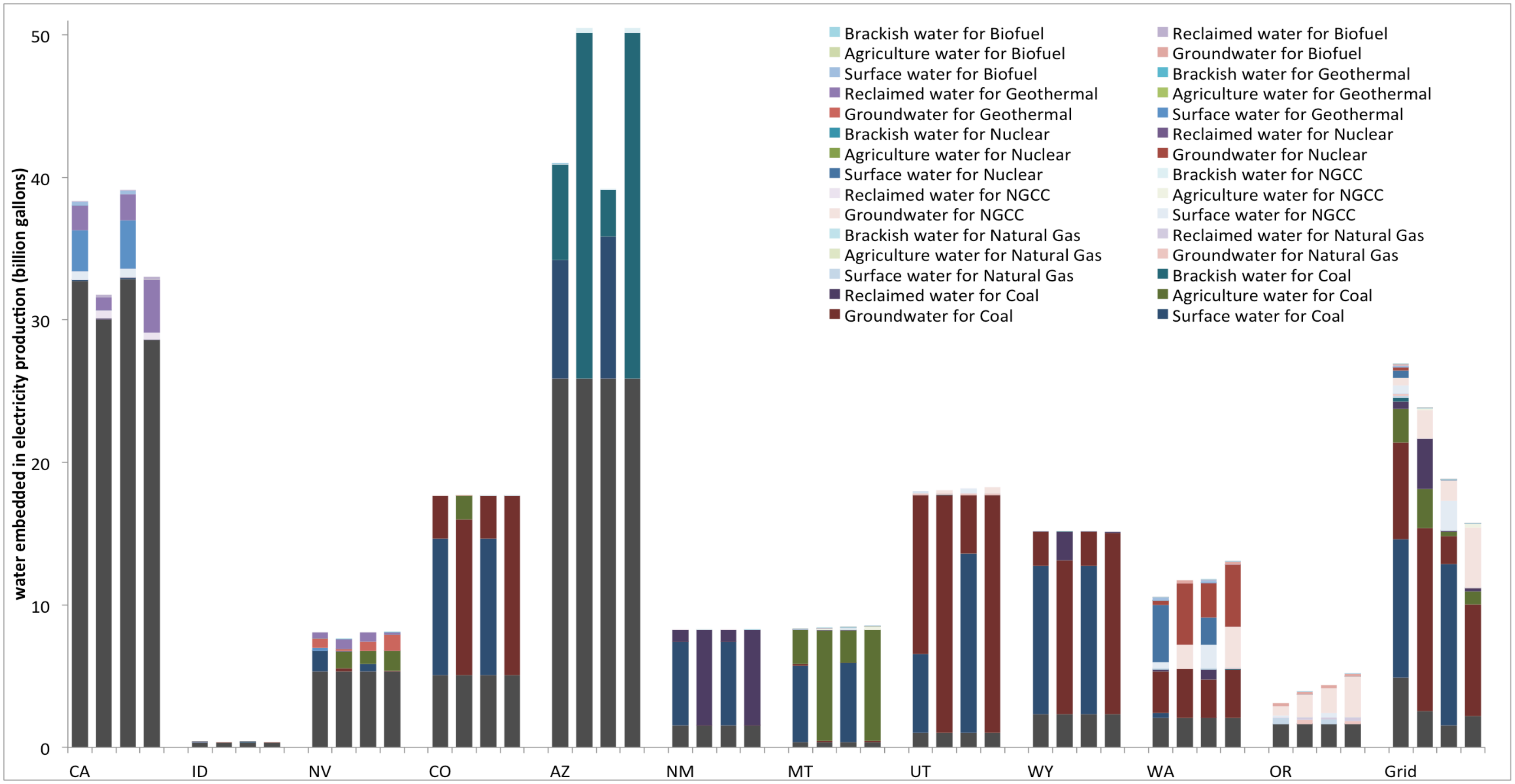


Figure 16. *Water types and volumes used for power production in the bounding scenarios. States are listed in order from greatest importer to greatest exporter. For each state, scenarios are presented from left to right: R0D0, RXD0, R0D30, RXD30. 'Low risk' water is in grey while 'at risk' water is colored according to water source. Note that most states compensate for lost surface water (blue) during drought with groundwater (red). But for MT, water from agriculture (green) is rarely used. Most 'at risk' water is consumed for coal plants (dark colors). Despite large capacity installations of NGCC in OR and WA (pastel colors), very little total water is consumed. AZ resorts to using expensive brackish groundwater (teal) because it is the only water source left unallocated in that state by 2040.*

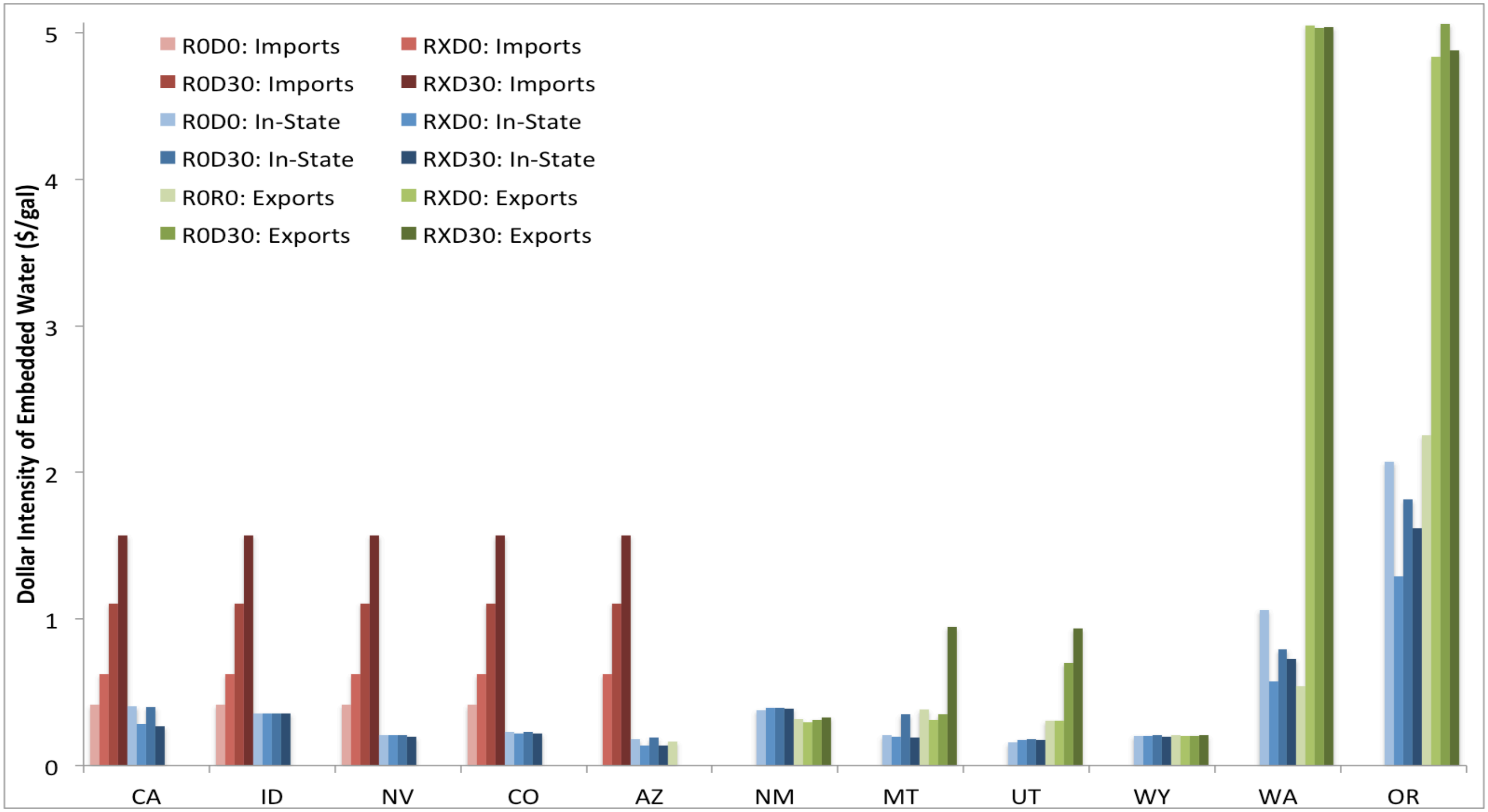


Figure 17. *Dollar intensity of embedded water for in-state production, imports, and exports in the bounding scenarios. States are listed in order from greatest importer to greatest exporter. Note that dollar intensity of water on the grid increases under drought and demand pressure. Exporters tend to export their more water efficient NGCC power resulting in more dollar intensive water for grid electricity than in-state production. This higher dollar intensity water can be thought of as being more valuable in that it generates revenue from power sales.*

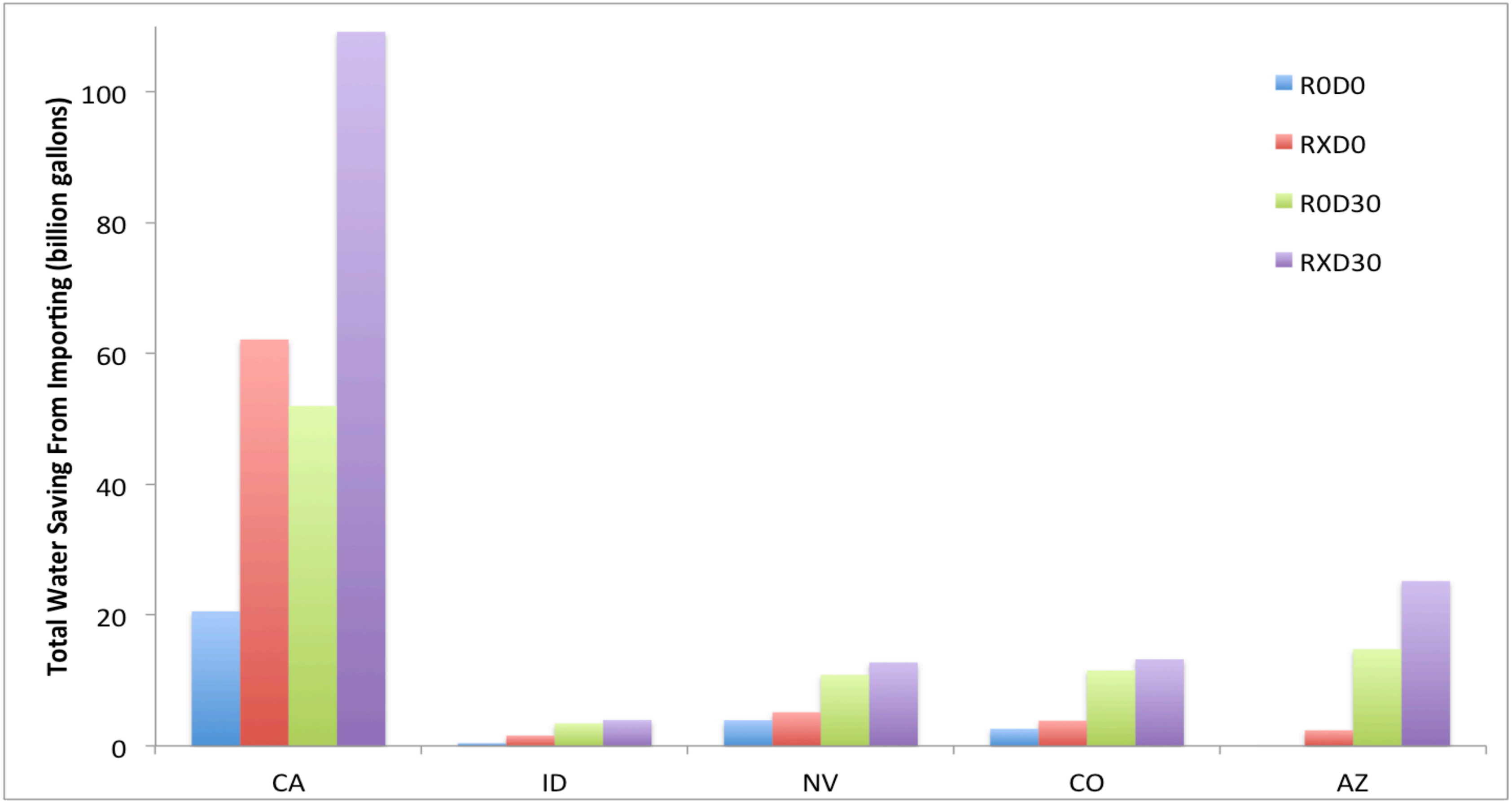


Figure 18. *Total savings of Western US water consumption due to trade in virtual water embedded in electrical power for each of the importing states for each bounding scenario. The method calculates the water saved in the entire Western US by outsourcing water use from less water efficient instate producers to more water efficient external producers. Results clearly show overall water savings under demand growth and drought conditions. Increasing water savings during drought and demand increases implies adaptation as exporters, OR and WA, expand low water intensity NGCC power. Adams et al (in review) show CA saving negative water from importing in actuality. This result shows the opposite because here, CA imports from OR and WA rather than AZ.*

DISCUSSION

The model results have several implications for the development of the Western electricity grid and its future resiliency to drought. The model shows that, as long as states adapt by pre-building capacity to make up anticipated shortfalls of hydro generation and can trade virtual water, the Western power grid will be able to cope with even the most extreme droughts. Yet, water limits do drive a shift in the location and type of power generation, and cause an increase in traded power and traded virtual water. On the Western grid, lost hydropower produces the greatest electricity shortfall during drought. When hydropower is lost, the deficit is supplied by new NGCC plants, regardless of the duration or severity of the drought, as NGCC is the most cost effective generation method (see Figure 12). The grid adapts by placing those plants in the states that can build most economically and outsourcing to states with higher in-state electricity prices. In this way, tradeoffs between local water/energy resource development and virtual water trade vary among states rather than among drought and demand growth scenarios. States that can build NGCC plants cheaply choose to do so, while other states forgo capacity expansion in favor of virtual water imports, during all drought and demand growth scenarios. As it is currently built, the model reveals no thresholds of demand increase or drought severity that produce dramatic or discontinuous change in the structure of the power grid.

Despite limited availability of unallocated surface water, many states have ample supplies of non-surface water that can be fed to ‘at risk’ thermoelectric power plants in the event of drought, albeit at an increased cost (see Figure 16). Obtaining access to these water sources for existing thermoelectric power plants is economically preferable to shutting down production and importing virtual water during drought. This result suggests that water consumption requirements for thermoelectric power can likely be managed as long as new power developments and existing at risk plants secure these non-surface water sources for cooling in advance of drought. Although potentially more expensive, reclaimed and brackish water sources are generally available in Western states and do not have competitors for their use. Model results also do not show significant appropriation of water from agriculture. Instead, states prefer less expensive potable ground water (see Figure 16). This result suggests that, if power plants are able to secure groundwater resources in advance, they will be unlikely to be forced to compete with agricultural users during droughts. Furthermore, plants in the West tend to be water efficient and mostly use recirculating cooling system, and as water intensive coal plants are retired for water efficient natural gas plants, this trend increases. The issue of the effects of drought on thermoelectric generation may be more severe for the Southeastern US, which sources a significant portion of its power from plants with once-through cooling system that require massive water withdrawals in order to operate, despite consuming little water.

The market for energy and the relative costs of production options drive behavior in the modeled system. The relative prices for in-state power as well as the relative costs to build new NGCC plants are the attributes that determine states' responses to drought and demand increases. Given current fuel price trends, NGCC plants are the most economically favorable generation option for new capacity development, and the model chooses capacity additions of NGCC as its sole method of drought and demand growth adaptation. The economics outweigh the spatiality of drought. Even under drought conditions in Northwest states, the economically optimal solution according to the model is to add NGCC capacity to the Northwest. As demand increases, the economically optimal solution will be to build new capacity in states that can do so cheaply, increasing the need for electricity trades between producers and consumers.

NGCC plants are also relatively water efficient, more so than the average grid mix in all but a few states. As older, less water efficient coal plants are gradually replaced by NGCC, average water embedded in electric power will decrease. The model shows this adaptation to drought and demand increases as average virtual water content in electricity on the grid decreases by 74% from the R0D0 scenario to the RXD30 scenario (see Figure 14). NGCC plants also coincidentally emit fewer greenhouse gas and other pollutants than coal plants (McRae & Ruppel, 2011). As NGCC plants gradually replace coal plants, there will be a corresponding decrease in greenhouse gas and other pollutant emissions from the Western grid (U.S. Energy Information Administration, 2013).

Because the model is structurally linear, it simply choses the least cost generation option to meet demand loads. In actuality, the proportion of the grid mix that the model designates as solely NGCC will be partly NGCC, partly single-cycle natural gas, and partly renewables – all low water technologies (U.S. Energy Information Administration, 2013). Adding future O&M costs increases for fossil fuel plants and decreasing capital costs for renewable options into the model, along with instate retail prices that adjust to reflect changing generation costs, may produce results that better capture the EIA's projected mix.

States that can build new capacity cheaply have a competitive advantage in becoming net exporters of electric power, especially during drought and as a result of demand growth. Conversely, states with high in-state prices (which are indicative of local regulations, market demand, and generation resource availability) are more likely to import power from neighboring states in response to drought and demand growth. But access to water will also be required for any large-scale capacity expansion. The economics of the model dictate that states with low capital costs and abundant water resources become exporters, but the model ignores regional transmission constraints such as local bottlenecks, the need for power to pass through intermediary states, and physical proximity to Southern CA, the largest market for electricity imports in the West. In actuality, it is AZ, not OR and WA, that currently has sufficient transmission to access this market at the lowest capital cost. However, given demand projections for electricity in CA over the next 30 years, considerable transmission capacity may need to be installed between AZ and CA in order to continue AZ's export advantage into the future. In this case, the total comparative costs between AZ supplying CA and the Northwest states supplying CA may be closer to parity. At its current spatial resolution, the model paints only a partial picture of how dynamics between local capital costs, regional water availability, and transmission expansion costs across corridors will determine electricity trade.

Yet, the trade patterns in the model suggest that virtual water should be traded in greater quantity than it currently is, and between different trading partners – especially under drought and demand increases. The model shows high volumes of virtual water flowing from water-rich states (OR and WA) to water short states (AZ, CA, and NV). Because of NGCC use reducing average water intensity of power production, the total volume of virtual water transfers decreases under drought and demand increases even as overall quantity of electricity trade increases. Even as electricity production becomes more water efficient, drought and rising demand increase the need for virtual water trade. This increase in water efficient electricity trade creates total water savings on the Western electricity grid as drought and demand increase (see Figure 18). This is a rational outcome of trade in electrical power under scenarios of water limitation.

In actuality, however, virtual water currently flows in the opposite direction – from AZ and NV to CA. This incongruity is largely related to other characteristics of exporting states such as favorable local regulations, ample energy resources, and relatively low internal electricity demands (Adams et al, in review). Contrary to the model's results, water does not yet appear to be a critical factor in energy production decisions, but because the model captures strong fundamental economic trends and constraints, it is likely that reality will converge with the model's projections over time as demand increases and capital turnover modernizes the grid.

The dollar intensity results reveal this incongruity. In the model, states with more water resources appear to value it more highly than those that are water limited, and they command a premium by exporting water-efficient power. It is reasonable to expect states with limited water resources to have higher dollar intensities for water in power production, but this is not the case in either the model or in actuality (Adams et al, in review), suggesting water abundance for the purposes of power generation. Yet, the model shows that the dollar intensity for electricity traded on the grid goes up during drought and in response to demand pressure. This result suggests that the model is simulating a rational market implicitly valuing embedded water as demand and drought limit water supplies, because the dollar intensity is a proxy measure for willingness to pay to outsource water use. During the modeled drought, states with limited water are willing to pay an increased premium for embedded water in order to allocate local water resources to other uses.

Allowing in-state electricity prices to reflect supply and demand changes during drought may improve the model and further refine dollar intensity results. Currently, in-state prices are static representations of long-term averages, even during a drought; and hourly and seasonal price fluctuations are not modeled. But, in reality, when hydro is not available due to drought, states that must import end up paying a premium for power (Bonneville Power Administration, 2002). However, the model assumes that all capacity has been pre-built – optimizing the production mix of a fully prepared grid. It may be that, even when prices are allowed to float, they will not change much in response to drought. Future work should explore the effect of floating in-state electricity prices on the system.

Although the model currently ignores demand fluctuations over the course of days and years, and in response to temperature increases, based on the current results, it is expected that if these fluctuations were included, the model would make up the power shortage with more NGCC produced in low-cost states and transmitted to states with high demand loads. The inclusion of this spike in transmission may change the results of the model. Transmission capacities are designed for peaks, but may become strained by high peak loads resulting from increased demand and decreased efficiency during drought. As the model calculates an average baseload grid mix, there is extra transmission capacity in the system that is not utilized in the modeled scenarios. It is likely that more transmission will need to be built along with the added capacity, to handle peak load export and import. But if the power grid evolves to increase the use of peak distributed energy generation, energy storage, or load shifting technologies, large transmission capacity installations might not be necessary, as there will likely be lower peak loads. How these technologies will interact with the higher peak demands projected for the future in Western US cities remains to be seen.

Even though each state runs a discrete least-cost optimization and then trades power, the overall system functions as a collective least-cost model of a partial economic equilibrium. As such, it ignores states' individual political or conditional incentives to buy or sell in favor of collective economic optimization. Instead of production being spread more evenly around the region, the few states with favorable economics are allocated the majority of capacity expansion in the model. The result is an increase in trade. Even though the model ignores load peaks (when most trade occurs), the optimization model suggests that even more trade is economically optimal. It is possible that the real-world politics of self-reliance and local contractual issues are distorting the market and lowering trade below levels that would be collectively beneficial.

Finally, these results are beneficial in revealing how electricity capacity and trading decisions on the Western power grid differ from a purely theoretical, economic model. The model suggests that increased cooperation between states and regulatory agencies could help to more evenly allocate water and energy resources through mutually beneficial trade. Because of their competitive advantage, it may be more economically practical for states with lower electricity prices and abundant water resources to export virtual water to water-limited states than for water-limited states to adapt internal generation systems. Additionally, water/energy planners would do well to consider virtual water trades and overall water use in their drought management plans. The current dominant drought management plan is to rely on virtual water sourced from (often) water-limited regions. This is likely not a dependable contingency plan should multi-basin drought occur. Building a more resilient, adaptive water/energy system that accounts for water efficiency and the risks of inter-basin electricity trading will be contingent upon the cooperation of regional utilities and governments to engage in collective risk management decisions (Bruch et al, 2011). The model suggests that, while adaptation is necessary to increase grid resilience to drought, the solution is feasible: increased low-water options such as NGCC and cooperation via water-efficient virtual water trade. As the climate becomes more unpredictable, droughts become more frequent, and electricity and water demands increase, such cooperation will become critical to ensuring that water and energy providers across the entire WECC region can rapidly and efficiently distribute both water and electricity to all users.

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