Actualizing water and energy systems integration: what is taking so long?

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Executive Summary: This policy analysis references lessons learned from an urban energy and water system case study located in the southeastern United States. Barriers to the generation of renewable energy within an urban water system, such as accessing needed utility data, the lack of tools to support integrated water and energy systems planning, and the lack of adequate options for metering and pricing of renewable energy within the Tennessee Valley Authority's service territory, are identified. Recommendations call for policies that support the standardization of utility data collection and access, and the integration of city and utility systems planning. They also call for incentivizing assessment tool development, as well as meter and pricing configurations that support the growth of district-scale renewable energy to reduce grid reliance.

I. Conceptualizing the Water-Energy Nexus

Water and energy system interdependencies, along with their separate management structures, are becoming more prominent as respective resources are increasingly stressed. The interaction and interconnection between water and energy supply and use is often referred to as the water-energy nexus (Baker & Behn, 2013). U.S. water and energy futures are uncertain, in part due to insufficient mechanisms to integrate the economic, environmental, and social variables that influence both systems (Biswas, 2004). The vulnerability of water and energy systems to threats such as terrorism, extreme weather, and market volatility, as well as their inextricable linkages to one another, prioritize much of the current urban water-energy research (DOE, 2014).

Energy is an essential part of water supply, purification, transfer, and utilization, and its consumption continues to grow (Apergis & Payne, 2012). In the U.S., 13% of electricity consumption is associated with water use, and this use contributes to over 290 million tons, or 5%, of annual U.S. carbon (CO_2) emission each year (Griffiths-Sattenspiel & Wilson, 2009). Water also plays an integral role in energy extraction, production, conversion, distribution, and use (Spang et al., 2014).

There is a rudimentary understanding of the complex and pervasive connections between water and energy. For instance, water processes that use energy include: source withdrawal and transfer, treatment and distribution, consumption and use, and wastewater treatment. Likewise, energy processes that use water include: extraction and processing of fuel, thermoelectric cooling, transport, waste treatment, and emission controls. One cannot be produced for human use without the other (Kenway et al., 2011).

Thermoelectric power is the largest water user for energy creation in the U.S., accounting for 49 percent of the country's total water withdrawal (Barber, 2009). Globally, the energy sector contributes the largest amount of greenhouse gas (GHG) emissions. It is commonly accepted that these emissions contribute significantly to climate change, which brings with it the hazards of increased intensity and frequency of extreme weather (Raupach et al., 2007).

While energy emissions contribute to climate change, water systems are noticeably impacted by climate change. Water systems can compromise life through scarcity and intrusion, and can be compromised in quality and quantity by various natural disasters attributed to climate instability. The North American drought of 2012 impacted over one third of the U.S., limiting water availability and constraining power plant operations. Hurricane Sandy hit vital water infrastructure and energy facilities in the states of New Jersey and New York later that same year, resulting in billions spent on restoration efforts (Hsiang et al., 2017). Most governments aren't prepared for investments of this magnitude, and are increasingly interested in proactive measures to insure system stability. Specifically, they need methods that contribute to system resiliency that also enhance society, the environment, and local economies.

The rising awareness of the importance of the water-energy nexus is demonstrated by the growing literature. Water-energy linkages have been examined from many angles (Desai & Klanecky, 2011; Gerbens-Leenes et al., 2009; Grubert et al., 2012; Sattler et al., 2012; Schnoor, 2011). The present state of knowledge around the water-energy nexus calls for systemic integration at all jurisdictional levels.

A variety of researchers and some government agencies have worked to synthesize information and define knowledge gaps. They find that obtaining useful data to understand causal relationships is difficult. There is a lack of methodological framework, together with resistance to holistic integration of water and energy systems. These constitute major barriers to scientific investigations into the urban water-energy nexus (U.S. DOE, 2014; Glassman et al., 2011; Kenway et al., 2011; McMahon & Price, 2011; Nair et al., 2014; Pate et al., 2007; U.S. Global Change Research Program, 2015).

While many studies examine the interconnections between water and energy systems, little work has been done to investigate the impacts of the management options associated with both resources together, particularly at the local level (Hussey & Pittock, 2012). Though discussed together, water and energy are still primarily managed and funded separately, due to jurisdictional constraints.

II. Localizing the Water-Energy Nexus

Cities are systems of systems operating simultaneously, and yet often separately. Systems integration is a generally desirable concept in municipal settings. This is because theoretically, integration means reduced management structures and fewer cross-system coordination points (Rotmans & Van Asselt, 2000). Cities can use technology to gather operational data from multiple systems, analyze it, and turn it into actionable intelligence. This increases decision-making capacity and causes less strain on human resources. It is no surprise that literature surrounding the water-energy nexus consistently calls for water and energy system integration.

There is an ever-increasing push for integration of water and energy management at the local level to achieve long-term system sustainability and resilience to acute and chronic stressors. Policymakers face complex challenges, requiring a mix of legislative and management strategies (Goldstein et al., 2008). While energy and water system managers are aware of the interdependence between energy and water systems, without these policies they continue to face silos in water and energy management, thus restricting their ability to unite decision-making processes (Halstead et al., 2014).

Water and energy system managers balance priorities and trade-offs to best use time and capital (Keeney & Raiffa, 1993). The choices presented by trade-offs depend on the specific situation (Makropoulos & Butler, 2010). System owners and operators, developers, regulators, and legislators make choices that shape communities, impacting response to external pressures. For the long-term sustainability of both water and electric systems, decision makers must work together and consider a myriad of variables, including: higher peak electricity demand; greater variability in the hydrologic system; the impact of climate variability on system reliability; ongoing pressures to reduce carbon emissions through reduction in energy consumption; and the economic impacts of these decisions (Hussey & Pittock, 2012).

Ultimately, it is at the local level that urban water and energy system changes can be tested, implemented, and potentially scaled. Putting digestible knowledge and usable tools in the hands of local decision makers are key components needed to move towards widespread systematic operational and infrastructure changes. Some urban centers already have water and energy use rapidly approaching or exceeding economic, environmental, and social limits (Hoekstra et al., 2012). They are striving now to adapt--changing water and energy system business models and investments to stay viable. Responsible management of both resources in the face of climate change, population shifts, and technology development is one of this generation's greatest challenges (Johansson et al., 2012).

Solving water-energy nexus problems is occurring piece-meal through implementation of various pilot projects, usually at the district-scale and microgrid level (Asmus, 2010). While many innovations are being tested, there is only modest convergence on best practices, and change is crisis-driven. Outdated regulations, unintegrated datasets, uncertainties about new technologies, unclear management practices, and a lack of communication among management structures are critical barriers to water system developments (Kenway et al., 2011).

Perhaps more influential than separate management structures and disparate data sets, however, is that the water-energy nexus remains a somewhat frustrating and evasive concept, and has yet to be presented: (1) with a case for engaging in system integration that speaks directly to factors that motivate both water and electric utilities; and (2) in tangible frameworks, so it is clear what actions utility managers can or should take to begin an integration process. The high-level water-energy nexus conversation often ignores local drivers for change, when it should instead start with them. For instance, an electric utility may lack the motivation to engage or integrate with an urban water system, when traditionally they interact with the water system through large hydropower facilities that they often own, and view water utilities as a customer. Or, a water utility may not be motivated to produce more energy than they can use to offset their own electric consumption when reducing their own utility bill is more of a priority than supporting the electrical system.

Once the case can be made for engaging both electric and water utilities at the local level, the process for integration can be presented as a suite of options. There is no single path that will achieve integration. Not all utilities and cities can or will utilize all available options. Energy markets and regulation will remain primary utility motivators. It is not enough to say that water and energy systems should be integrated. A case needs to be made for it, using primary motivators as the starting point. Then, options need to be presented as a menu of options. This allows utilities to make their own actionable roadmaps towards system integration once they see it is within their best interests.

With the case-making context in mind, and understanding that no two utilities will follow exactly the same water and energy systems integration pathway, research was conducted to explore one aspect of making the water-energy nexus tangible. It delves deeply into only one integration angle: small-scale hydro in urban water systems, and the possible motivators for implementing it.

Using water to store energy (hydro generation) at a large scale is a mature field; it is still one of the most efficient energy storage methods available. Implementing small-scale hydro generation is somewhat newer, especially at the microgrid level. Small-scale hydro is proving viable in some locales, and is being explored with greater frequency in the literature.

This policy analysis is based on the lessons learned from extensive research of one city's water and energy system. The intent of the research is to model small-scale hydro energy storage throughout an urban water system to understand if such a system could be used to generate energy to shave costs off community peak electrical demands. To conduct such a study, local water and energy data sets had to be obtained, modeled, and compared to understand orders of magnitude between community energy consumption and water system storage capabilities.

III. Barrier 1. accessing and formatting water and electric utility data

Data was collected from Cleveland Utilities (CU), a municipal water and electric utility that services the City of Cleveland, Tennessee. Data collection over the course of one year included gathering water and energy consumption data sets, geographic information system shape files (ArcGIS, Environmental Systems Research Institute, Redlands, CA), a model export of the CU water distribution system, and planning documents to understand projected population growth patterns. The length of time it took to obtain simple community-wide water and energy data sets almost halted the research effort. Lessons learned from this process include: identifying who oversees the needed data, understanding what matters to them when the case for data is made, understanding what specific data is needed, knowing when to request data sets and in what sequence, and learning with whom to coordinate data transfer.

The first barrier was to obtain concept buy-in. Many meetings were held with the CU Water and Electric departments to obtain approval of the research concepts, to understand the local water system operational preferences, to obtain the CU water system model, and to gather the needed energy system data. There were several key concerns to address, including customer data privacy and presentation of the research outcomes to various audiences.

Ultimately, the water model was provided for transfer into the U.S. Environmental Protection Agency's open-source water distribution modeling software, EPANET2. The model is based on monthly water consumption data by meter ID and sector type. Water consumption data contained monthly totals by water source (produced and purchased water), monthly totals by commercial and residential sector (gallons and percent), and total loss by percent and volume. Addresses and names were stripped from files – no customer identifiers were used in this work, and a letter of non-disclosure was issued to CU to assure that this research would not violate utility customer privacy policies.

The second and more significant barrier was obtaining community-wide electrical data. Collection attempts spanned 10 months and included multiple meetings with CU electric utilities staff. Four overarching challenges were ultimately overcome: (1) A shared understanding was reached that customer identifiers were not needed to conduct the study - a non-disclosure agreement was also signed to insure that any data provided would be kept private; (2) Staff turnover in the Information Technology (IT) department changed who would ultimately provide the data and when; (3) A shared understanding was developed over time on the data request components – this was finally accomplished by comparing the data request to the structures of the existing CU databases, and reaching a compromise on what could easily be provided in light of that structure; and (4) A shared understanding was developed between the perceived and actual time required to export and transmit datasets.

Data gathering challenges are not specific to CU. Utilities across the U.S. are being asked to share water and energy consumption data that will allow urban sustainability to advance. Big data sets like these provide the ability to make smarter decisions concerning updating codes for building retrofits and new construction, for example.

Utilities are often reluctant to share data because of the staff time it can require fielding requests, and due to customer data privacy concerns. Additionally, there are concerns surrounding the public sector gaining greater knowledge of utility revenue models. This results in significant opportunity costs for communities. It stunts growth in the energy field by placing data needed to make transformational changes out of reach, and forces non-utility parties such as cities, researchers, and planners to develop work-arounds, and to make assumptions that would be unnecessary if data were scrubbed of customer identifiers and released in aggregate sets (Stimmel, 2014).

Access issues are only the first energy data hurtle. The format of the data is crucially important, so the person receiving the data can understand what the data is, and what city-specific coding refers to. For instance, in the first attempt to collect CU electrical consumption data, the CU Electric Division provided 2015 monthly energy consumption data by meter and sector type, as well as hourly electric meter readings for 1 month in 11 sector codes, which were not defined. The 2015 monthly electric meter dataset provided current and previous month readings, and total water usage data by: (1) sector (commercial, large commercial, small commercial, and industrial - but no residential); and (2) meter ID. Meter names were undescriptive of customer sector, and no spatial identifiers were provided. Most meters had hourly readings, though some hours are missing throughout the dataset.

However, after further negotiations with the utility, an electric consumption data set was delivered that contained hourly energy consumption (in kWh) by substation (16 total) and sector classes (11 total) for 4 months in 2016: January, April, July, and November – representing the 4 seasons in east TN. Like the water demand dataset, no customer identifiers were used. Because there are no customer identifiers, the best way to spatially locate electric demand is by electrical substation.

Finally, electrical substation identifiers were provided in the dataset, as was a substation and circuit zone map for import into ArcGIS. This came from yet another division within the utility. Due to the challenges of data availability and gathering, it had to be assumed that electricity can be consistently delivered throughout the electrical system, and that there are no weak spots in distribution within the CU electrical distribution system. These assumptions were acceptable, because the methodology focused on the water system, not the electrical system.

Once the electrical data were in hand, it became quickly evident that hourly data in such magnitude had to be restructured and formatted so it could be manipulated into the comparison calculations the research required. This process took 1 month of careful translation of utility codes into discernable identifiers, through back and forth dialogue with the utility. Ultimately, it required a complete spreadsheet restructuring so that data could be visualized by sector, month, and hour. Because this process was manual, it had to be checked and rechecked to insure data transfer was precise, and that restructuring did not compromise the data set itself.

Another challenge is that even within a single electric utility, databases often do not interface with each other. ElectSolve (Shreveport, LA) is used as CU's meter data management system (MDMS), providing an integration platform for smart meter reading by the 15 electrical substations within CU's service territory. Another system is used for customer management and billing (CMB), and neither of these interface with GIS (for circuit mapping overlays), or with each other. In sum, CU has 13 databases with over 36,000 meter records. Each IT data manager specializes in a specific system. Most do not have working knowledge of the other systems, making data compilations and comparisons more difficult.

For communities that want to examine water and energy system integration, the ideal data gathering scenario to reveal seasonal-use patterns would be to obtain at least 1 year of electric demand data. Ideally, these data would be hourly for 12 months, to understand the demand shapes of a 7-day week (168 hrs.), month (720 hrs.), or year (8,760 hrs.). In the CU case study, such a data set would have resulted in a data file of 280,320,000 records. CU does not have the capability of uploading such large data files to their FTP site for sharing.

IV. Barrier 2. inadequate integrated water and energy modeling capabilities

While energy data were being gathered, another barrier was the existing water model proved to be intensely complicated, especially for a small city. CU is a webbed water system unconfined by city limits. Connections to neighboring water systems allow for the purchase and sale of water between jurisdictions. Understanding what normal operations looked like involved starting with confirmation of boundary conditions (model inputs), and comparing model outputs to old calibration reports. This learning process took 6 months. A practitioner familiar with the water system would not have had this challenge, but a researcher needs to take time to fully understand a case-study system, so energy scenarios built within it can be developed with confidence.

Additionally, the water model was not smart enough to allow for integration of the energy consumption data. Energy calculating capabilities within the water system model were not executed by model time step. The only representation of energy consumption within the model was averages of distribution pump energy consumption. Integration of energy consumption data at a community level within the water model was not possible. Thus, energy comparisons to water system storage capacity had to be calculated manually in Excel-based spreadsheets.

To understand why smart integrated water and energy systems are so difficult to model, it is important to understand the basic components of both systems. There are four primary components in urban water systems: (1) the original water source; (2) a built system designed for the creation and transport of clean (potable) water; (3) a built system for the transport and treatment of black (sewer) water, and; (4) a built system that deals with runoff (stormwater) inputs. In addition to insuring that reservoirs, groundwater wells, and aqueducts can supply water needed to meet the varied demands from an urban area, there is also the component of operation and maintenance of water treatment plants and water distribution systems that transport water (with specific pressures) to users. Once water is used, wastewater must be collected and transported for treatment and discharge (Loucks et al., 2005). Additionally, the urban stormwater drainage system must be separate from the potable and sewer infrastructure, and overflows can be costly and dangerous. It is a vastly complicated system that is difficult to model, operate, and maintain, even before considering any energy system interactions.

Urban water systems rely on engineered components to provide water supply, transport, and treatment. There are above or below-ground collection points from watershed sources; above or below-ground water transfer mechanisms (aqueducts, tunnels or pipes); treatment facilities; underground water transfer pipes; storage facilities such as reservoirs, tanks, and towers; and an extensive piping system that transfers clean water to buildings, black water from buildings, and gray water from storm runoff. The piping network also services outlets around urban areas, such as fire hydrants, and industrial facilities that require significant water inputs for operations (Loucks et al., 2005).

Water constantly moves through city piping networks. If viewed as a form of potential energy generation, both the various uses it is destined for, and the stages it may be in (potable, black, gray) are secondary. Portland, OR is currently replacing a gravity fed potable water pipeline with one that contains 42-inch turbines connected to an external generator. The turbines do not slow the water enough to impact the rate of pipeline delivery, and the usable energy to be generated is estimated at 1,100 megawatt hours (MWh) each year. This could cover the ongoing energy needs of roughly 150 homes (Electronic Engineering Journal, 2015). Over the next 20 years, it is estimated that the system will produce 2 million dollars in electricity sales.

Energy storage in the urban water systems typically manifests itself in water tanks and pressurizing systems used to obtain the right amount of flow in specific situations, not necessarily to generate electricity that is transferred to the electrical grid for use. Smaller urban water systems often store water in cisterns or pressurized containers. Taller structures frequently feature rooftop or on-site storage to insure high water pressure on upper floors. In lower elevations, communities may also add pressurizing components, like pumping stations, at above or below-ground water intakes (Loucks et al., 2005). When searching a local water system for energy storage opportunities, space for tanks may pose site-specific issues.

In general, tanks are located throughout a water system to: (1) equalize flow and minimize diurnal (or daily) demand curves; (2) equalize pressure throughout the system over the course of a day; and (3) increase water system resilience to acute (i.e., fire) and chronic stresses (i.e., drought). There are several different classifications of storage tanks: (1) surface or ground, which is at or below ground level; (2) standpipe, which is also at ground level and can be used in place of overhead storage on hilltops; (3) elevated or overhead storage; and (4) pressure or bladder tanks, which offer little to no storage, and function as a demand buffer so pumps aren't coming on and shutting off as frequently (Loucks et al., 2005).

As the urban water system is made up of four major components, so is an electric utility system: (1) generation; (2) transmission; (3) subtransmission; and (4) distribution. In developed areas, electricity is created at a generating site from a fossil or renewable fuel. Long distance transmission enables access to remote renewable energy resources that can displace fossil fuel use in electricity creation. Hydro, wind, and sometimes solar generating sources are usually removed from urban areas, often because the cost of siting is less in more remote areas. Connection costs play a large role in determining whether a renewable alternative is economically viable (Blaabjerg et al., 2004).

To transmit electricity, an initial form of energy is converted into electricity by spinning a magnet of coiled electrical conductors. Switchyard transformers increase voltage from around 69,000 volts (V) to 230,000 V - or even more, if it is extra or ultra-high voltage - in preparation for transmission. Electricity is put onto the transmission system and moved by voltage conductors using direct current (DC) or alternating current (AC) through interconnecting power lines, or transmission networks (Electric Utility System Operation, 1997).

While DC is still used in some locations where the generating station is close to the consumer, AC is more common because it can move electricity over long distances with less energy loss than can DC. The transmitted electricity is sent to substations near populated areas at a frequency of either 50 or 60 hertz (Hz). In transmission, it mingles with electricity produced at other generating sites. Large industries or commercial consumers sometimes are connected at the primary distribution level and receive distribution voltages delivered as three-phase power in high voltages (Electric Utility System Operation, 1997).

Sub-transmission moves the electricity from substations to distribution substations inside populated areas. Substations have circuit breakers that allow for disconnection from the transmission grid or distribution lines. Medium industries can take power directly from the sub-transmission system. For most consumers, however, the sub-transmission system is connected to distribution substations that use transformers to lower the transmission voltage and deliver as single-phase electric power. Medium voltage circuits can typically accommodate as low as 601 V and as high as 69,000 V. It is carried to distribution transformers via primary distribution lines near end users (Electric Utility System Operation, 1997).

Voltages are stepped down by distribution transformers to a lower voltage secondary circuit for the appropriate user utilization level (around 120 or 240 V for household appliances in residential areas, for example). Electricity is sent by the distribution transformer to the busbar, which acts as an electricity conductor. The busbar sends the electricity to secondary distribution lines and then, to consumers. Service drops connect secondary distribution lines to building electrical meters, which deliver single phase power to the remaining electricity consumers (smaller industries, commercial establishments, and residential homes) at voltages below 600 V (Electric Utility System Operation, 1997).

Distribution systems, in many urban settings, have been systematically moved from overhead wires and placed underground by local electric utilities. This option, while costlier, creates less need for right of way, eliminates visibility and fly-over zone issues, and reduces storm damage potential. In these undergrounded conditions, distribution can occur in subsurface utility ducts and face less service disruption from line damage, though disruptions can also be harder to locate when they do occur. Overhead transmission and distribution lines are still common, however, especially in suburban or rural areas. In addition to being less expensive to place, they are not as load-constrained, due to thermal capacity, as underground lines are (Johnson, 2006).

Radial distribution networks connect consumers to a single supply source. These are usually found in suburban or rural areas, and feature switchboards for rerouting during emergency situations. Network distribution is when several supply sources operate in tandem, servicing areas with highly concentrated demand. Distribution networks can be reconfigured for system optimization and to actively curb power loss (Baran & Wu, 1989).

Some integrated modeling efforts dealing with both water and energy systems are published. They are rare, however, and very few of these use actual city case studies to test their algorithms, operational conditions, and integration point theories. Many different modeling, mapping, and statistical analysis tools can be paired in almost any number of ways to answer interdisciplinary and cross-system questions. There is no standardization of types of tools to combine, types of data that local utilities should collect, or clear methods for how to use synchronous tools for system integration decision-making.

Local utilities maintain models of their local water and energy distribution systems as a standard procedure. These models are used to analyze historical and predicted water and energy demand rates. Forecasting models such as these can simultaneously compute outcomes under a variety of factors associated with chronic stresses, such as economic development, population growth, human behavioral patterns, and climate change. Traditional forecasting models (time series analysis and multivariate regression, for example), and even more advanced modeling techniques (artificial intelligence programming, like neural networks or expert systems), are frequently used to predict short and long-term demand (Khatri & Vairavamoorthy, 2009).

However, these models are not typically connected. They function as separate entities, and are maintained by different departments. The following are barriers to integrating local water system models with the local energy system, regardless of city size or regional location: (1) political boundaries or jurisdictions are wide and varied, making integration legally challenging; (2) systems are planned, funded, operated, and measured for performance in isolation; (3) integrated system standards haven't yet emerged; and (4) different methods of collecting and storing data contribute to uncoordinated reporting (Liu et al., 2015). Innovation inhibitors include: infrastructure repair and rehabilitation needs, rate control, regulatory demands, procurement laws, climate change impacts on water resources/water scarcity, customer resistance to rate increases, lack of any unified framework for evaluating innovations or consistent guidance on what innovative actions to implement, and the current workforce's education level (Frantzeskaki & Loorbach, 2010).

Even if water and energy system integration was more common, limitations within modeling structures mean that they are fallible tools at best. Models are only as good as their inputs and computation capabilities, and many cities – small and large alike - lack lengthy and continuous historical water demand records, to say nothing of data describing the circumstantial and dependent variables of water and energy demand (Qi & Chang, 2011). Modeling tools need to be intuitive and integrated, so that examining water and energy system integration is not so inaccessible.

While some of these challenges seem daunting, they can also be catalysts of new and better methods of operating urban municipal and investor-owned utilities. In short, urban water systems of all shapes and sizes are faced with a myriad of challenges. Factoring in the energy system adds a significant layer of complexity that most civil servants and utility workers are unprepared to address. This lack of integrated systems thinking also impacts research efforts, as it can prove difficult to obtain or create tools capable of performing the water and energy system analysis needed to answer long-term planning questions.

In the case study used for this policy analysis, the modeling and analysis tools available were used, despite their limitations. Water and energy data were manipulated to determine if additional storage in the water system can offset community peak energy demand, and in what physical configurations. Additional storage was also assessed for water system resiliency impact in the face of a doubling population. All water and energy demand comparisons for both current and future demand scenarios, were performed manually in Excel (Microsoft Corp, Redmond, WA), instead of within a more user-friendly framework that an integrated model would have provided.

Finally, costs were assigned to energy storage scenarios within the water system to understand if the economic impacts were realistic within local planning and financing horizons. The economic analysis revealed yet another barrier in implementing local water and energy system integration. As with all energy storage methods, pumped hydro storage is not completely efficient. It takes more energy to pump the water from the lower reservoir to the upper reservoir than can be generated by release of water from the upper reservoir. Hydropower needs peak demand pricing to make it viable. This leads to the third barrier this policy analysis explores: the model with which renewable energy is priced within the Tennessee Valley Authority's service territory.

V. Barrier 3. inadequate renewable energy meter configurations and pricing

Energy is an open market commodity: traded, sold, and purchased at price points that increase and decrease in correspondence with real-time energy demands. In addition to purchase price, energy is valued by other components as well, such as security (Månsson et al., 2012), building and/or system efficiency (Kwak et al., 2010), renewable sources (Bergmann et al., 2006), policy development (Komarek et al., 2011), and multiple methods and materials used to implement storage (Dunn et al., 2011; Kienzle et al., 2011; Miller, 2012).

Electricity prices are influenced by many factors. In addition to the cost of a kWh, energy prices include costs to finance, build, operate, and maintain the electric grid, including transmission and distribution power lines, and to build energy-source power plants (Lijesen, 2007). For-profit utilities may also include shareholder financial returns in electricity prices (Eto et al., 2000). A summary of key factors which influence the price of electricity , adapted from information published online by the U.S. Energy Information Administration, is as follows (EIA, 2017).

First, the cost of fuel varies by unit. For instance, natural gas is sold by dollar per thousand cubic feet, while coal is sold by dollar per ton. Electricity generators at power plants can have high fuel costs during periods of high demand. Second, there are initial construction investments, as well as ongoing operation and maintenance (O&M) for each power plant in operation. Third, utility or Public Service Commissions may regulate energy prices in some states. Others may have a combination of regulated and unregulated pricing structures. Transmission and distribution may be regulated, for instance, while generators may not be. Fourth, electricity transmission and distribution systems used to deliver electricity have ongoing maintenance costs, including damage repair from storms or other acute stresses. Finally, while weather conditions allow for renewable energy generation (sun for solar, wind for turbines, rain for hydropower), extreme temperatures can increase energy demand. In turn, this can drive pricing structures to meet increased heating and cooling needs (EIA, 2017).

The actual costs to supply electricity changes moment-by-moment (Oren, 2000). Most consumers pay rates based on the seasonal cost of electricity, and electricity prices are usually highest during summer peaks, due to the addition of more expensive generating fuel sources to meet increased cooling demands (Hatami et al., 2011). Price changes not only to reflect variations in energy demand, but also to reflect the availability of primary and/or secondary generation sources, the price of fuel by unit, and the availability of power plants to come online (Sims et al., 2003).

Electric utilities class customers by type, and this classification determines what that customer pays. Residential and commercial consumers usually pay the most, because they require voltages to be stepped down and distributed at finer scales. Industrial consumers, on the other hand, use more electricity and can receive it at higher voltages, thereby making the receipt of electricity less expensive and more efficient for the power supplier and utility. In some regions, industrial customers can pay close to the cost of wholesale electricity (Rothwell & Gomez, 2003).

In 2016, the annual average price of electricity in the United States was $0.10 per kWh. Annual averages by sector are as follows: commercial customers paid an average of $0.10 per kWh; industrial customers paid an average of $0.07 per kWh; residential customers paid an average of $0.13 per kWh, and the transportation sector paid an average of $0.10 per kWh. These are presented in averages because, like the cost of water, energy prices vary by local service territory. This is due to the factors such as the local availability of fuels and fuel costs, the availability of online power plants, local utility pricing structures, and local regulations. For instance, in 2016, the average annual electricity price in Hawaii was 23.87¢ per kWh, but only 7.41¢ per kWh in Louisiana (EIA, 2017).

Energy models are commonly used to determine electricity pricing. The neural network approach is perhaps most common. One study proposes a neural network analysis to forecast short-term electricity prices (Catalão et al., 2007). With the rise of competitive electricity markets, short-term forecasting is replacing long-term forecasting. Catalão et al. propose a competitive framework to derive energy market bidding strategies. A 3-tiered neural network trained by the Levenberg-Marquardt algorithm is used for forecasting week-ahead electricity prices. The accuracy of the price forecasting attained by the neural network approach is evaluated, using cross-continental data from the electricity markets of Spain and California.

Another study uses a neural network model for short-term electricity price forecasting in deregulated energy markets. The model consists of price forecasting, simulation, and performance analysis. It accounts for variables that impact electricity prices in real-time, such as time, load, reserve, and historical pricing factors. Reserve factors are found to enhance forecasting performance. The model manages price increases more efficiently, because it considers the median as opposed to the average (Yamin et al., 2004).

As with valuing energy from a real-time market standpoint, valuing energy storage is not a new concept, though examples of valuing it specifically in an urban water system are rare. The Electric Power Research Institute (EPRI) created an energy storage simulation software used to evaluate the potential cost effectiveness of energy storage under customizable assumptions. The Energy Storage Valuation Tool (ESVT) evaluates the cost effectiveness of storage in 3 broad use cases, in 31 separate scenarios. In a California case study, nearly all use cases indicate cost effectiveness. These storage cost saving estimates have not been met however, due to cost structure and regulatory hurdles. The EPRI analysis provides a break-even cost for each storage scenario, which the utilities can use as a benchmark for cost effectiveness. The storage industry can use outputs as goals (Goldstein & Smith, 2002).

Examples of potential cost impacts and benefits of increasing water storage are as follows:

- Operating costs will increase to charge water storage tanks (pumping) and extract energy during water tank release. With a favorable peak energy pricing structure, the energy required to charge storage costs less than peak storage release for energy generation. Energy demand pricing structures matter.
- Infrastructure costs to the system will increase with the addition of storage. Increased water storage can be used to generate electricity in times of normal water system use, or can be allocated to meet water system demand and pressure needs.
- New generation technology costs can be high, so it is important to understand the value streams of storage in demand times. Capturing energy from water tanks requires simple technology for generation and grid connections, and it is possible that the equipment needed for generation could pay for itself over time.
- New generation plant costs are enormous. Stored energy can work to defer new generation plants.

Energy storage is an extremely important variable in energy systems planning (Eyer & Corey, 2010). However, due to the case-by-case nature of its implementation, it is also difficult to consistently value. The costs and benefits of an energy storage project are almost always locational (Schoenung et al., 1996). Costs vary because of regulatory, market, and regional differences (Carmona & Ludkovski, 2010). The range between on-peak and off-peak power prices determines the value (Williamson, 1966). When viewed as an alternative to fossil-fired peaking resources, it is becoming increasingly competitive in some regions (Palensky & Dietrich, 2011).

The benefits of electricity storage are long documented and well established (Copeland et al., 1983; Jewell et al., 2004). However, though electricity storage has evident merit, it is usually considered to be too expensive for deep energy market impact (Ibrahim et al., 2008). The costs of various storage technologies are continually analyzed for implementation possibilities by the private and public sectors. In general, prices are found to be dropping, and economic analysis performed on specific case studies shows that it is often economically justified (Poonpun & Jewell, 2008).

Because of these variables, caution must be used when contemplating using CBA and ROI analysis for renewable energy sources as transferable benchmarks. For this reason, energy storage CBA and ROI studies are typically conducted by energy technology type: solar photovoltaics (PV), for instance (Kaldellis et al., 2009), or wind (Le & Nguyen, 2008). There are 2 commonly used metrics to evaluate energy storage, however: (1) the ratio of storage to the system size; and (2) a comparison of the total energy output from the storage to the energy consumption of the entire system (Maloney, 2017).

One study compares the feasibility to the economics of pumped hydro storage (PHS) when combined with battery storage for a renewable-energy powered island (Ma et al., 2014). The research was undertaken to find the most suitable energy storage scheme for local decision-makers. Findings conclude that PHS is cost competitive when combined with battery storage and controlling variables, like increasing energy storage capacity and days of system autonomy. The renewable energy system, coupled with PHS, presents technically feasible opportunities for continuous power supply in remote areas. Another study examines the ability of PHS to support and optimize a small island's energy system. This study concludes that including pumped storage to allow for larger market penetration of renewable energy sources improves both system resiliency and operations (Brown et al., 2008).

Advances in the use of small PHS distributed throughout an urban water system can directly support a community's sustainability goals (Ardizzon et al., 2014). Cities rely on strong economic systems, healthy environments, and human-centered design for a total picture of community health (Haughton & Hunter, 2004). Energy sources directly impact each of these factors (Capello et al., 1999). For a sustainable future, energy should be primarily derived from non-fossil sources, while also being flexible, safe, reliable, affordable, and abundant (Brownsword et al., 2005). Renewable energy generation sources are constrained from adoption in many instances by the intermittency of their outputs (Barton & Infield, 2004). PHS on a small, distributed scale can serve as a viable option for communities as they move into transforming their energy and water systems to include energy storage systems (Dell, & Rand, 2001).

However, most local decision-making officials don't have time, or the capacity, to assess cost-benefit models for water systems, and learn how to use them. When the element of connecting the water system to the energy system is added, uncertainties and knowledge gaps increase substantially (Lubega & Farid, 2014). In many cases, these officials are appointed for political reasons, rather than for technical skills. When this happens, good policy and decision-makers rely on analysis from system specialists to make sound, timely decisions. Researchers and policy makers interact best when goals, technologies, methodologies, and tools have been digested by the scientific community and are presented to local communities in a way that is easy to understand, with clear decision points and recommendations. Recommendations are strongest when cost benefit analysis (CBA) and return on investment (ROI) data is presented with them, therefore, what's technically possible can be clearly translated into real-world constraints and timeframes (Schoenung et al., 1996).

When cities and counties consider investment options in water infrastructure, they examine water use by potential development pattern (Dandy et al., 1984). They consider the age of the system's components and estimate replacement costs, the cost of doing nothing, and the costs of phasing upgrades (Swyngedouw et al., 2002). GIS is a common tool used to overlay these development projections (Maantay et al., 2006). The municipal scenario-based planning process can utilize a wide variety of tools, using baseline data and localized challenges to project economic, social, and environmental scenarios over specified time horizons (Otterpohl et al., 1997). More and more, communities are turning to the private sector to share the enormous costs of upgrades (Beecher, 1997).

Perhaps the most interesting aspect of the gravity-fed pipe generation pilot project in Portland, OR is the use of a third-party finance model (Electronic Engineering Journal, 2015). The private sector is installing and operating it for 20 years, recouping costs, and then selling the system to the city. This financing method points to the critical role that infrastructure plays in how much storage and potential energy production urban water systems can produce. Most communities in the U.S. host old water distribution systems, and water-piping infrastructure can date back to over 100 years in some instances (Al-Barqawi & Zayed, 2006).

Leaky pipes impact water delivery and transfer, potentially inhibiting the ability of the system to efficiently host storage and generating equipment (Misiūnas, 2008). Because of the heavy maintenance costs a local utility bears, there is often little room to be proactive (Grigg, 2005). Through tax incentives and credits for renewable energy generation, the private sector can access resources inaccessible to governments (Menanteau et al., 2003). This can, in turn, buy down the capital costs of planning and implementation. If the private sector then recoups the costs of the system with an acceptable profit margin, it can sell the system at fair market value to the city or county. That government may continue to realize savings over time, but also faces maintenance of the now-aging infrastructure (Wiser & Pickle, 1998). This finance model manifests itself repeatedly in public-private partnerships centered on renewable energy generation (Lewis & Miller, 1987).

Distributed energy storage (DES) refers to stationary electric energy storage systems located at or near the end use that they serve, such as residential, commercial, or industrial buildings (Zogg et al., 2007). DES systems, in combination with advanced power electronics, will play a significant role in the electrical supply systems of the future. Right now, when energy storage systems are integrated into conventional electric grids, each requires its own unique design. This process has direct budget implications to utilities contemplating implementation of these systems (Carpinelli et al., 2013).

Because of the growing move towards energy system transformation (Jacobsson & Lauber, 2006), more flexibility with distributed generation and storage is needed (Atzeni et al., 2013). Small and medium storage systems are needed in both the supply and demand sides as storage moves from concentrated storage (reservoirs, in the case of traditional PHS) to distributed storage (equipped with intelligent power electronics conversion systems that control small scale PHS, for instance). As with any newer system technology, models, planning tools, and budget methods that will enable the use of storage devices at the DES level are not yet widely used (Mohd et al., 2008).

Providing utility services requires access to significant capital and debt (which requires assurance of timely debt payments). Long-term plans must be developed to meet these financing requirements. Cities and utilities prepare annual budgets for the upcoming fiscal year, as well as an estimated budget for some years beyond the upcoming budget year. For instance, in the CU case study, the long-range plan included with CU's FY 2017 budget covers FY 2018 to 2026. It accounts for energy provider rate adjustments to avoid unexpected increases and to prevent financial surprises on the distribution end of the energy spectrum. CU makes assumptions when preparing long-term budget projections. Assumptions include:

- Projected volumes, using historical averages and statistical modeling
- Rate adjustments to match system demands from operating and capital expenditures
- Projected expenses with inflation variables
- Development of capital requirements spanning fiscal years, to account for changing service demands, new regulations, and maintenance and upgrades of existing facilities
- Interest rate and payback period estimates, for new bond issues
- Maintenance of cash balances, to meet payment obligations

Examining customer growth over time is a key part of creating these assumptions. For instance, in 1997, CU had 25,537 electric and 24,053 water customers. In 2015, the numbers grew to 30,808 and 30,928, respectively. Examining performance is another key part of creating these assumptions (City of Cleveland Tennessee Annual Budget, FY 2016-2017).

The Tennessee Valley Authority (TVA) makes the electricity used by 9 million consumers across a 7-state region, including the U.S. states of Tennessee, Kentucky, Alabama, Mississippi, Georgia, North Carolina, and Virginia (TVA, 2017a). TVA sells power to local electric distributors (such as CU), who then sell power to customers in their service territories. Like other major electric suppliers in the U.S., TVA charges power-purchasing electric utilities a monthly fuel cost.

Roughly 75% of TVA's power supply comes from fuels-based electricity sources, like coal, natural gas, oil, and nuclear fuel rods (TVA, 2015a). TVA's costs change when these fuel prices change, due to variables such as weather conditions or global supply-chain changes. This results in monthly cost increases or decreases, that are passed on to the customer via the local distributor. In addition to fuel costs, TVA's total monthly fuel costs include fixed costs, such as power plant operations and transmission line maintenance.

For example, the variable portion of the TVA total monthly fuel cost for a residential customer could be around \$10 per 1,000 kilowatt hours (kWh). The fixed portion of the TVA total monthly fuel cost for a residential customer could be around \$20 per 1,000 kWh. The total customer bill in that example will be \$30 per 1,000 kWh. If that household uses 2,000 kWh in a month, they will pay \$60 in total monthly fuel costs. It varies not only by household, but also by sector. Commercial and industrial TVA monthly fuel cost rates will be quite lower than for the residential sector.

Weather, fuel type used to create power, and time-of-use influence the cost of each kWh produced. It costs more to generate electricity during peak demand than it does during non-peak periods. TVA has begun to implement peak-demand pricing structures, beginning by season. Once automatic metering infrastructure metering common throughout distributors in the TN valley, peak-demand pricing can be implemented by time of day. Peak demand is somewhat predictable. Summer afternoons and winter mornings are 2 examples of seasonal peak-demand periods.

TVA peak-demand hours occur in the afternoons and evenings of summer (June to September) and early to mid-mornings in winter (December to March). According to TVA's fact sheet, *The Price of Power*, winter peak is from 5:00 AM eastern time (ET), to 11:00 AM ET. Summer peak is from 1:00 PM to 9:00 PM ET (Tennessee Valley Authority, 2015). Summer months are June, July, August and September; Winter months are December, January, February and March; and Transition months are April, May, October and November (TVA, 2015c).

The cost of electricity also increases as commerce and population increase. To meet rising demands, at times more expensive power must be purchased from other companies, or more expensive generation methods must be brought online, such as quick-start natural gas plants (Tennessee Valley Authority, 2015a). Peak demands are growing faster than energy generation infrastructure. Peak-demand pricing structures are not designed to create additional revenue streams for power producers or distributors. Instead, they are intended to incentivize, through a direct market mechanism, reduction of peaks to avoid a need for new power plants. TVA is using a variety of new infrastructure-avoidance methods, including energy-efficiency incentive programs, peak-demand pricing, and, to a small extent, use of intermittent renewables (TVA, 2017a).

A rate adjustment is the process by which energy providers increase rates to match revenue needs. According to TVA's final assessment report, *Refining the Wholesale Pricing Structure, Products, Incentives, and Adjustments for Providing Electric Power to TVA Customers* (2015b), recent TVA rate adjustments are of 2 types: (1) general electricity pricing structures and rates; and (2) specific adjustments, credits, and products. Within these 2 categories, pricing structures and rates are loosely grouped by size and service mechanism: (1) small-scale wholesale standard service-by-power distributors, which includes residential, commercial, and small industrial customers; and (2) large-scale wholesale service requiring over 5,000 kilowatt (kW) demands, including manufacturing and commercial customers.

This second category includes both individually-metered customers serviced by distributors under non-standard service provisions, as well as customers directly served by TVA. Using data from Appendix A of TVA's final assessment report, Table 1 shows the TVA wholesale rate design with time-of-use pricing structure, as well as time-differentiated rates for the TVA General Service Class.

Table 1. Summary of TVA's 2016 Wholesale Rate Design with Time-of-Use Pricing Structure (TVA, 2015b).

TVA Wholesale Rate Design with Time-of-Use Pricing Structure					
Season	**On-Peak Demand/kW**	**Maximum Demand/kW**	**On Peak Energy/kWh**	**Off-Peak Energy/kWh**	**On-Off Peak Differential/kWh**
Summer	$7.49	$2.75	$0.05356	$0.03156	$0.02200
Transition	$6.63	$2.75	$0.03429	$0.03429	$0.00000
Winter	$6.63	$2.75	$0.04352	$0.03352	$0.01000

In 2016, TVA distributors adopted the latest customer rate schedules. TVA rate schedules are structured by kWh use, so a type of customer can fall into several different classes if they operate more than 1 property.

For instance, a city in the TVA service territory can be in the GSA-2 class for larger buildings (like city hall), a GSA-1 class for smaller buildings (like fire stations), and an

LS class for lighting (street lights, for instance).

Electric distributors bear the burden of explaining TVA rate schedules to customers. Table 2 shows the most recent TVA rate schedule by kWh use, with data adapted from a distributor's website designed to help customers understand their bill structure (Nashville Electric Service, 2017). CU now operates under this rate schedule.

Table 2. Summary of TVA's 2016 Rate Structure by Rate Schedule Demand (Nashville Electric Service, 2017).

General Power Rate	Demand by Rate Schedule
Schedule GSA-1	Greater than 50 kW and less than or equal to 1,000 kW
Schedule GSA-2	Less than or equal to 50 kW
Schedule GSA-3	Greater than 1,000 kW and less than or equal to 5,000 kW
Schedule GSB	Greater than 5,000 kW and less than or equal to 15,000 kW
Schedule GSC	Greater than 15,000 kW and less than or equal to 25,000 kW
Schedule GSD	Greater than 25,000 kW
Large Manufacturing	**Demand by Rate Schedule**
Schedule MSB	Greater than 5,000 kW and less than or equal to 15,000 kW
Schedule MSC	Greater than 15,000 kW and less than or equal to 25,000 kW
Schedule MSD	Greater than 25,000 kW
Time-of-Day Rate	**Demand by Rate Schedule and Optional Commercial Schedules**
Schedule TGSA-1	Less than or equal to 50 kW
Schedule TGSA-2	Greater than 50 kW and less than or equal to 1,000 kW
Schedule TGSA-3	Greater than 1,000 kW and less than or equal to 5,000 kW
Optional Commercial Rates	*Schedule TDGSA, Schedule TDMSA, Schedule SGSB, Schedule SGSC, Schedule SGSD, Schedule SMSB, Schedule SMSC, Schedule SMSD*
Outdoor Lighting	**Contract Requirements**
Schedule LS	Street and park lighting, traffic signals, athletic field installations, outdoor lighting for individual customers

There are 2 primary costs to consider for an electricity storage system: energy cost/rating and power cost/rating (Ibrahim et al., 2008). Energy cost for storage is the purchase price of the rechargeable equipment and infrastructure (batteries or pumped-hydro reservoirs, for instance) that store energy. The energy rating of a storage system is the total energy the system can store. The energy rating of a storage unit can be calculated using capacity in units. For instance, reservoir gallon capacity can be converted into kW or kWh, and batteries have ampere-hour (Ahr) ratings that can be converted into watt-hours (Wh), kWh, or Ahr (Zakeri & Syri, 2015). In this research, energy cost is expressed in unit-cost of stored energy, or in U.S. dollars (USD) per kWh.

While also expressed as the cost-per-unit of power (USD/kWh), power costs measure the purchase price of 1 unit of electricity (to run the pumps that fill a hydropower reservoir, for instance). The power rating of a storage unit measures the unit's instantaneous capacity, or how quickly the storage system can be re-charged. Power and energy costs together provide the total initial capital cost of a storage unit (Hrafnkelsson et al., 2016).

TVA Green Power Providers (GPP) is a renewable energy program that structures how TVA accommodates customer-generated small-scale renewable energy (TVA, 2017b). Customers within the TVA region have requested access to "net metering," which is a bi-directional meter that measures: (1)

electricity current flowing from a system to meet localized energy consumption, and (2) current flowing onto the grid, if any is left unused by the system owner. Net metering is commonly used in other utility service areas, and is attached to a billing mechanism that credits renewable energy system owners for any electricity they put onto the grid, after their own energy needs have been met (Stoutenborough & Beverlin, 2008).

In response, TVA created an alternative to net metering that they call "dual metering". More complicated than net metering, dual metering involves the installation of 2 meters at a renewable energy system: one to measure power output from the system, and one to serve as the billing meter. Rather than allowing customers to harvest generated energy for their own use, TVA instead requires that TVA purchase 100% of the energy generated by GPP participants, while they continue to purchase electricity from their local distributors. TVA will buy the renewable energy output at the retail electricity rate and retain the renewable energy credits for the duration of a 20-year agreement. TVA uses this generation to credit their "Green Power Switch" program, which allows other customers to buy renewable energy credits to offset their own fossil-based energy use (TVA, 2017b).

The GPP program is designed for residential and commercial customers of local TVA distributors. How could a power purchase agreement be constructed for a TVA distributor (CU, for instance) to be compensated for any potential small-scale hydropower generation? Ideally, and if they were in a different utility's service area, CU would be able to use any hydro-generation to offset their own water system's energy consumption. However, unless open to net metering negotiations with a local power distributor, TVA will purchase in full any hydro-power generation (or, "generation credit") from CU under a 20-year GPP agreement (TVA, 2017b). This is only if CU presents any hydro-generation as a secondary use, the primary purpose of the water system still being to meet water customer demands. An appendix supplies technical details of the program as it would impact CU, should they pursue community-wide energy generation from water system storage.

VI. Policy recommendations

Policy recommendations stem from the barriers discovered in this analysis. They are broken into 3 major categories: data sharing policies, integrated planning policies, and renewable-energy generation metering configurations and pricing structures. Specific descriptions of these proposed policies are as follows:

i. Data sharing policies

Water and energy system data need to be more readily available to the researcher and practitioner. It should not take 1 year to obtain/format data if the water-energy nexus is to advance from theory into practical application at an acceptable pace. Local utilities should create data sharing policies, not only as a service but also to clarify good data sharing practices within their own employee ranks.

Specifically, these policies should be designed to clarify: (1) what data are available for public use; (2) how the data can be requested; (3) how the data can be legally used; and (4) how requests are evaluated, accepted, or rejected. If a utility has adopted such a policy, employees are then equipped to answer inquiries (from academia, for instance) with details about standard non-disclosure agreements and procedures, estimated timelines required to service acceptable data requests, and the provision of a data key to understand utility codes for identifiers (such as sectors). These new guidelines and timelines would make the data gathering process clearer and more approachable for both customer/researcher and utility.

The proposed policies would serve to protect both parties from unreasonable expectations, unexpected delays, and surprise outcomes. They would also reduce discomfort when data are ultimately requested, because questions can be answered against a decision-making framework of which both parties are aware. Policies to clarify data transactions are key to advancing the ability to answer questions around water and energy system integration in a timely manner, a process currently in infancy. Utility data access is crucial to advancing this field, and policies around data sharing will provide a greater comfort level around this process.

Challenges to implementing data sharing policies include a perceived threat to the existing utility business model, which does not champion transparency. There is also the perceived threat to customer privacy. Interestingly, emerging data sharing platforms such as RentRocket, which rely on utility customers uploading their household energy data (such as bills, energy efficiency upgrades, etc.), have strong initial market success in large part because utility data sharing policies are mostly non-existent. The privacy concern is being tested by crowdsourcing applications which fill utility customer knowledge gaps, answering consumer questions such as which rental houses have chronically high utility bills. It's potentially in thee utility's best interest to determine the terms dealing with how energy consumption data are shared and accessed.

ii. Integrated planning policies

Smarter integrated water and energy system assessment tools are needed. For instance, what if water systems supervisory control and data acquisition (SCADA) real-time data dashboards were linked to the local energy systems SCADA? What if users could toggle between the two to understand water system generation potential during times of peak community energy and water use? Or, what if a water system network model could generate multiple potential growth configurations on its own, directly relating to energy system structure and development patterns, skipping the tedious node-by-node process of model expansion?

Currently, there is not much incentive for the entities who can access critical data sets to develop or to support development of such tools. There is comfort in jurisdiction. Water and energy systems are complicated on their own without merging them together to create ever larger data sets.

Policies can provide the currently absent incentive to find more sophisticated ways of exploring water and energy system integration. For instance, if a city and its utility agree that water and energy system integration can help them achieve their community sustainability and resiliency goals, a policy can be developed that mandates utility and planning departments to work together to test various system integration techniques in the form of pilot projects. Top-down direction is needed to motivate local utility and city planning practitioners to effectively work together.

iii. Renewable energy peak pricing and net metering policies

Water system electricity-generating storage at a community-wide scale will not be viable in most urban areas until the prices paid for energy consumption and generation increase. Attractive renewable energy pricing structures from energy suppliers are especially needed during peak demand times, to reduce overall system energy load. Offsetting energy loads defers the need to permit and construct new power plants, which is attractive to all sectors.

In the interim, policies that allow for net metering are needed in the utility territories lacking this system. These areas are shown in

Figure 1, taken from the Solar Energies Industry Association's website (SEIA, 2017). This will allow renewable energy generation system owners to offset their existing energy consumption costs. The southeastern U.S. should not be operating under a different set of rules than the rest of the country. As many energy providers with renewable energy targets in place have found, net metering is essential to adopting renewable energy generation.

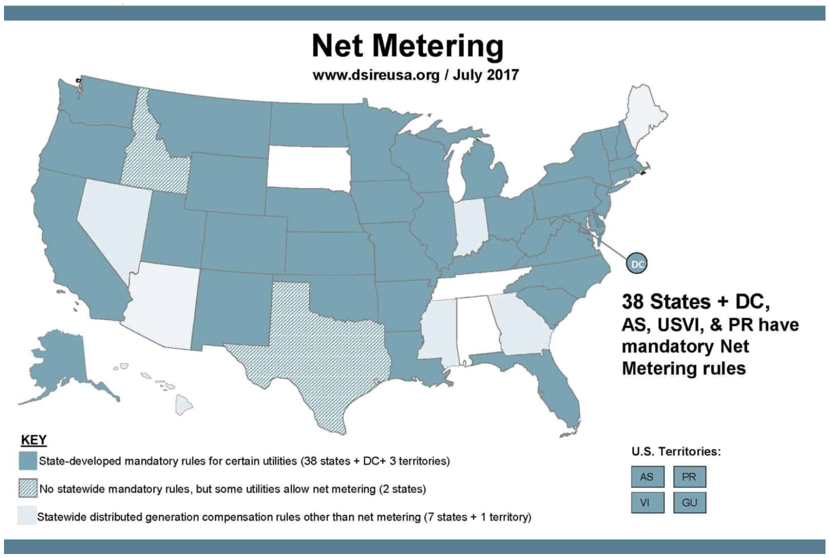

Figure 1. Net Metering Capabilities in the U.S. (SEIA, 2017).

Renewable energy generation is much more attractive if policies are in place that allow for: (1) competitive peak-energy pricing from renewable sources; and (2) net metering. The prospect of cost savings on monthly utility bills can then become the primary incentive to implement private renewable energy generation systems. If pennies are offered on the kWh for renewable energy generated during peak energy demand times, and if the metering configuration prohibits the off-setting on-site energy use, renewable energy system payback periods will remain prohibitive.

Removing single-source energy reliance through a distributed energy storage and grid configuration is beneficial to both the consumer (through utility cost-savings), and the utilities (by reducing the potential for interruptions in energy distribution). System reliability and resiliency increases, while customers are empowered to control their monthly utility bill. Additionally, unused electricity can be sold to the energy provider at a cost reflective of the renewably generated energy's worth.

VII. Conclusion

This policy analysis stems from barriers identified during research efforts to integrate water and energy systems in a case study city. Barriers include lack of a structure to enable data sharing, lack of integrated planning tools, and insufficient renewable energy-generation metering configurations and pricing structures. Findings conclude that without top-down policies in place to remove these barriers, exploration into real-world applications of the localized water-energy nexus will remain stunted.

Creating city and utility-driven policies that clearly outline data sharing processes and procedures is recommended, because having standard data collection processes in place reduces confusion for both utility and utility customer when data requests inevitably arrive. Also, mandating integrated system planning efforts is a must to making sure managers of water and energy systems are talking and working together. Maximizing urban system efficiencies through integration is attractive to taxpayers and elected officials alike.

Finally, supporting favorable renewable energy-generation metering configurations and pricing structures is important to insure that renewable energy is not cost-prohibitive. Making renewable energy fiscally attractive results in increased installations, thereby reducing reliance on a centralized energy grid. The utility gains resiliency, and the customer gains savings and, in some cases, profits from the energy generation. Without adoption of policies in these three categories, the localized water-energy nexus will remain a theoretical concept, seeing little on-the-ground application in U.S. urban areas.

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Technical Details Appendix

According to the 2017 GPP Guidelines, TVA accepts a minimum of 0.50 kW and a maximum of 50 kW per contiguous-property customer. A GPP applicant must provide its projected annual usage (kWh), as well as their proposed nameplate capacity of the qualifying system (TVA, 2017b). To TVA, the generation credit refers to accrued credits a GPP participant earns by generating renewable energy. It is calculated by applying the energy charge in the applicable retail rate schedule to the kWh energy output the generation meter measures. CU would likely be classed in the GSA-1 retail rate, which is the rate schedule TVA applies to industrial (large) customers (Nashville Electric Service, 2017).

The generation meter measures alternating current (AC, from a non-inverter-based energy system), and can be interval, non-interval, or both. In addition to submitting a professional estimate of expected generation, the GPP participant must adhere to a TVA annual capacity-factor-by-generation type. "Low-Impact Hydropower" is 50%, for instance. Using the kW per year generated in one of the case study energy storage scenarios (89,175 kWh over 3 days), the CU equation to calculate maximum nameplate capacity for generating tanks is as follows:

*3,303 kW per year * 3,285 discharge hours per year *50% capacity factor = 5,424,961 kWh, where* (1)

*kW = (89,175 kWh * 121.67 3-day periods in a year) / 3,285 generating hours per year*

This means that by TVA GPP standards, CU would be generating too much (more than 50 kW) hydro-power to fit into this program. A special distributor agreement would need to be developed between CU and TVA, ideally one that allows for net metering. It would benefit CU to be able to offset water system energy costs before returning any power to the grid. TVA, while not being able to capture the renewable energy generation credit in this case, would still benefit from no longer needing to provide for CU's water system energy load, which could become a self-servicing, independent microgrid.

This agreement would dictate terms, such as the TVA purchase price of CU on-peak energy generation by kWh, as well as the rate CU would pay for energy to re-charge storage during off-peak hours. However, lacking such an agreement, and for the sake of this fiscal research to understand scenario costs, the TVA rate schedule TGSA-2 is initially used to calculate on-peak and off-peak generation prices.

Time-of-use rates provide the basis for determining energy generating and pumping costs by kWh. In the case of the 2 CU water distribution system storage scenarios, concentrated and distributed, storage tank operation is designed to charge tanks during off-peak electrical use times of day, and to discharge them during peak times of day. Storage tanks discharge during daily peak-electrical periods (1 to 9 PM ET), and recharge each day during off-peak hours (from 9PM to 12AM ET). Water tanks are modeled using controls that prompt tank discharge to generate electricity during 1 peak-electrical diurnal curve, for a period of 9 hours in a 24-hour day, 356 days per year.

Referencing Table 2, the TGSA-2 schedule is for customers that fall into the greater than 50 kW and less than or equal to 1,000 kW use range. According to this rate schedule, during the summer season, the customer is charged $0.09 per kWh used during on-peak hours, and $0.06 per kWh used during off-peak hours. Depending on scenario, CU can generate between 200 and 400 kW from storage discharge, and requires between 300 and 600 kW to recharge it (assuming a 70% pump efficiency ratio). It is assumed for the purposes of this research that CU could be paid $0.09/kWh for on-peak generation, and be charged $0.06/kWh for off-peak energy consumption to recharge the water storage tanks (TVAc, 2017).

Negotiated energy rates, whether paid for generation or charged for pump energy consumption, would be subject to the following conditions: (1) base energy use charges increase or decrease according to current TVA rate adjustments and power purchase rate changes; (2) the "hydro allocation credit," or what is paid for energy generated, is also subject to increases or decreases to the applicable wholesale power rate schedule; and (3) any contractual arrangements made between TVA and CU, as the local distributor.

Research from the CU case study resulted in financial analyses of water storage and demand scenarios in both concentrated-storage distributed-storage configurations. The concentrated-demand scenarios' annual energy generation potential from peak-hour discharge by tank is 10,849,992 kWh/year. This is calculated by summing tank discharge in 5-minute time steps over a 3-day model run and extrapolating that kWh (89,175) over 1 year. The potential pump energy used to recharge tank storage is 15,499,889 kWh/year. It is calculated by summing energy consumed by pumps that are refilling the generating tanks during off-peak hours and extrapolating that kWh (127,393) over 1 year.

Fiscal cost analysis calculations are originally performed using TVA's TGSA-2 schedule, which designates $0.09/kWh used during on-peak hours, and $0.06/kWh used during off-peak hours. However, when this rate was put into the Excel-based financial cost analysis spreadsheet built to perform these calculations, buying electricity at $0.06/kWh and selling electricity at $0.09/kWh produces an annual financial loss of $585,669. Using this pricing structure, annual operating costs for an initiative like this will not break even until the electricity can be sold for somewhere between $0.14 and $0.15/kWh.

For this reason, the TVA TSGA-1 schedule is applied instead. Use of this rate would have to be negotiated as a special term of the power purchase contract, but it would allow CU to be paid $0.17/kWh for on-peak generation, while purchasing off-peak pumping power at $0.06/kWh, thus managing a slight annual financial gain, rather than an annual operating loss.

The results of the concentrated scenario's fiscal analysis indicate that CU would have to purchase off-peak electrical energy at $.06/kWh and sell it at nearly $3.25/kWh to pay the project off in 1 years' time. The total installation cost estimate for the concentrated-storage configuration is $30,103,259. When combined with the total annual operating cost and the estimate of total annual value of energy generated, the ROI for the concentrated storage configuration is 112 years. This is not within local planning and financing time frames.

The distributed storage scenario's annual energy generation potential from peak-hour discharge by tank is 5,439,133 kWh/year. This is calculated by summing tank discharge in 5-minute time steps over a 3-day model run and extrapolating that kWh (44,704) over 1 year. The potential pump energy used to recharge tank storage is 7,770,190 kWh/year. It is calculated by summing energy consumed by pumps that are refilling the generating tanks during off-peak hours and extrapolating that kWh (68,863) over 1 year.

As with the concentrated storage scenario's cost analysis, the TVA TSGA-1 schedule is applied, allowing CU to be paid $0.17/kWh for on-peak generation, while purchasing off-peak pumping power at $0.06/kWh, to be able to operate with an annual financial gain, rather than a loss. The distributed storage scenario's direct capital cost estimates total $15,718,065. When combined with the total annual operating cost and the estimate of total annual value of energy generated, the ROI for the concentrated storage configuration is 129 years. Energy prices would have to double to bring the ROI near the 20-year planning and financing horizons of a local utility.

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