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Grid Impact of Reservoir Thermal Energy Storage for Data Center Cooling

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ABSTRACT

Data centers are projected to account for up to 12% of total U.S. electricity demand by 2028 according to Lawrence Berkeley National Laboratory, up from 4.4% in 2023. Expanding electricity system infrastructure to reliably serve this rapid data center demand growth is one of the largest near-term challenges that the U.S. electricity system faces. In addition to increasing power demand, rapid data center growth could drastically increase water demand for cooling if evaporative cooling is used. If dry cooling and air-cooled chillers are used to reduce data center water consumption, cooling would drive peak data center demand, which in turn drives the electricity system investments needed to serve that demand. Cold reservoir thermal energy storage (RTES), a form of cold underground thermal energy storage (UTES), can be used to shift data center cooling loads to off-peak hours, reducing electricity system costs while also reducing data center water consumption. Using advanced, open-source power system modeling tools GenX and ReEDS, this paper investigates the impact of RTES for data center cooling on the bulk power system. We estimate the electricity system investment and operational cost savings that RTES could provide and evaluate the impact of RTES system duration on these savings. We find that seasonal RTES could reduce the grid cost of adding data center capacity by 3% to 6% in Virginia. These savings are primarily achieved by reducing cooling demand during net peak load hours, which decreases the firm generation capacity required to meet the planning reserve margin with additional data center load. This firm capacity reduction could be achieved with durations as short as 12 hours in Virginia. These findings suggest that RTES for data center cooling could appreciably lower the power system costs of serving rapidly growing data center load.

1. INTRODUCTION

This paper provides preliminary estimates of the potential grid benefits of reservoir thermal energy storage (RTES) paired with data center cooling systems. We quantify this value by incorporating a data center cooling system model with RTES into capacity expansion models. The work presented in this paper is part of an ongoing study first presented in Winick et al. (2025), and final results are forthcoming.

Data center demand is rapidly growing in the United States: Shehabi et al. (2024) project that data centers could increase from 4.4% of U.S. electricity use in 2023 to up to 12% by 2028. Although cooling is currently the minority of data center electricity demand, the most energy efficient cooling equipment uses evaporative or adiabatic assisted cooling, consuming significant amounts of water. Limitations on water access may thus prompt data center developers to use less water-intensive, less energy-efficient cooling equipment, such as dry coolers and air-cooled chillers. For this reason, data center cooling demand could become a significant source of grid stress that coincides with existing summer demand peaks driven by residential and commercial air conditioning.

Cold underground thermal energy storage (UTES) could reduce the grid impact of data center cooling peaks. UTES refers to technologies that store thermal energy in subsurface geologic media for later use, enabling temporal decoupling between thermal energy production and thermal energy demand (Winick et al. 2025). UTES systems are commonly categorized into borehole thermal energy storage (BTES) and reservoir thermal energy storage (RTES), also referred to as geological thermal energy storage (GeoTES) (Pepin et al. 2021; Winick et al. 2025).

RTES systems store thermal energy in naturally occurring porous and permeable geologic formations, such as aquifers or sedimentary reservoirs, enabling substantially larger storage volumes and higher thermal power than BTES through a combination of conductive and advective heat transfer (Pepin et al. 2021). A national-scale pre-assessment by Pepin et al. (2021) identified substantial RTES technical potential across several U.S. geologic regions, including the Coastal Plains, the Michigan Basin, and the Basin and Range, regions that are also expected to experience significant data center development.

Recent studies have established RTES as a technically and economically promising cooling technology for data centers. Zhang et al. (2024) evaluated the techno-economic feasibility of RTES for data centers with peak cooling capacities of up to 70 MW but did not consider configurations that integrate mechanical chillers. Oh et al. (2025) analyzed RTES paired with dry coolers and heat recovery for a 5 MW data center over a 20-year lifetime, focusing on data center–level performance rather than power system impacts.

This study contributes to the literature by examining the grid-level benefits of RTES for a large data center with 1,000 MW of cooling demand. In addition, this work considers an RTES configuration that includes air-cooled chillers in addition to dry coolers.

2. METHODS

We incorporate a simplified model of RTES in a data center cooling system into two open-source capacity expansion models, GenX (Bonaldo et al. 2026) and ReEDS™ (Regional Energy Deployment System) (Avraam et al. 2025). To estimate the potential grid value and benefits of RTES in the absence of detailed cost information, we compare the grid cost of serving additional data center demand with conventional cooling technologies with the grid cost of serving the same additional data center demands that are cooled by cold RTES which is installed at no cost. We focus on a case study of the PJM power system with RTES added in northern Virginia. This approach is summarized in Figure 1 along with key outputs.

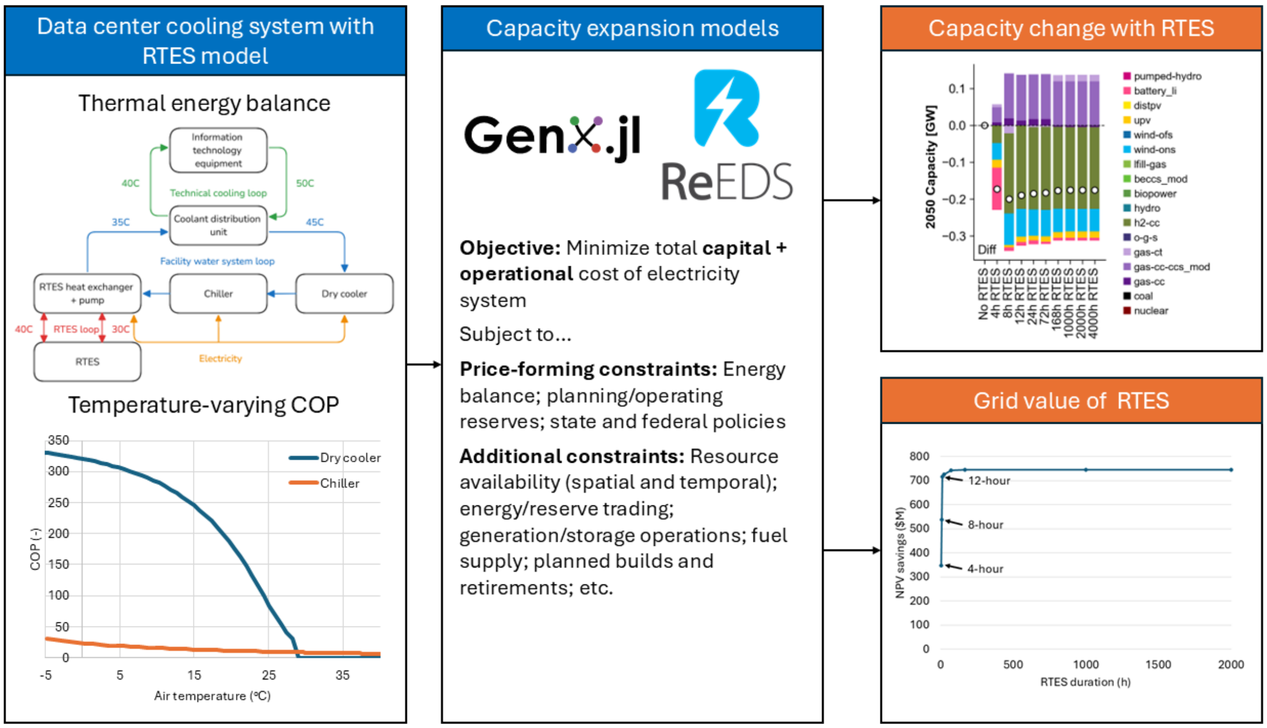

Figure 1: Summary of methods used in this paper and key outputs.

2.1 Reservoir thermal energy storage model

We incorporate RTES into the GenX and ReEDS models using the approach shown in Figure 2. The objective of this optimization model is to minimize electricity costs while meeting data center cooling demand. We assume thermal cooling demand is constant and equal to the non-cooling load of the data center, which includes computing and lighting.

In the design considered, heat is rejected from the data center into the facilities water system loop (primary heat rejection system) via a heat exchanger on the technical cooling loop (see Figure 2). The working fluid is then cooled to the required data center supply temperature by some combination of the dry cooler, chiller, and RTES heat exchanger. To minimize data center water consumption, we focus on a cooling system with a dry cooler rather than an evaporative cooler. We assume constant data center thermal cooling demand and a constant mass flow rate for the working fluid in the facilities water system loop.

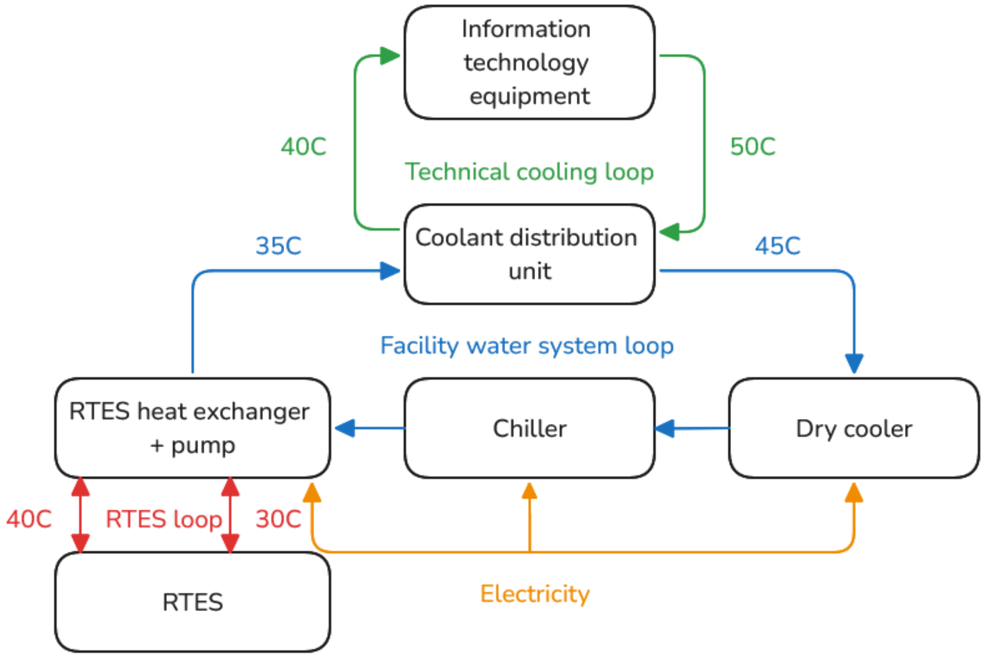

Figure 2: Model of data center technical cooling loop, facilities water system loop, and RTES loop.

Both the dry cooler and chiller are modeled with temperature-varying coefficients of performance (COPs), which determine how much electricity is required to achieve a certain amount of cooling. These curves are shown in Figure 3. While dry coolers are highly efficient at low ambient temperatures, a chiller is required to meet cooling demand at high ambient temperatures. The dry cooler output temperature is further limited by its approach temperature, which sets the minimum difference between the outdoor air temperature and the dry cooler output temperature. The minimum chiller COP in 2007 through 2013 and 2016 through 2023 weather years modeled in GenX is 6.38, which corresponds to a peak cooling demand of 157 MW for a 1,000 MW_{th} cooling load. For resource adequacy calculations, ReEDS considers the top 20 net peak load across 15 weather years (2007 through2013 and 2016 through 2023). The minimum chiller COP during these hours is 8.5, which corresponds to a peak cooling demand of 120 MW during net peak load hours. This peak cooling demand requires an additional 120 MW plus a capacity planning reserve margin of firm capacity generation and transmission to meet cooling demand for this data center.

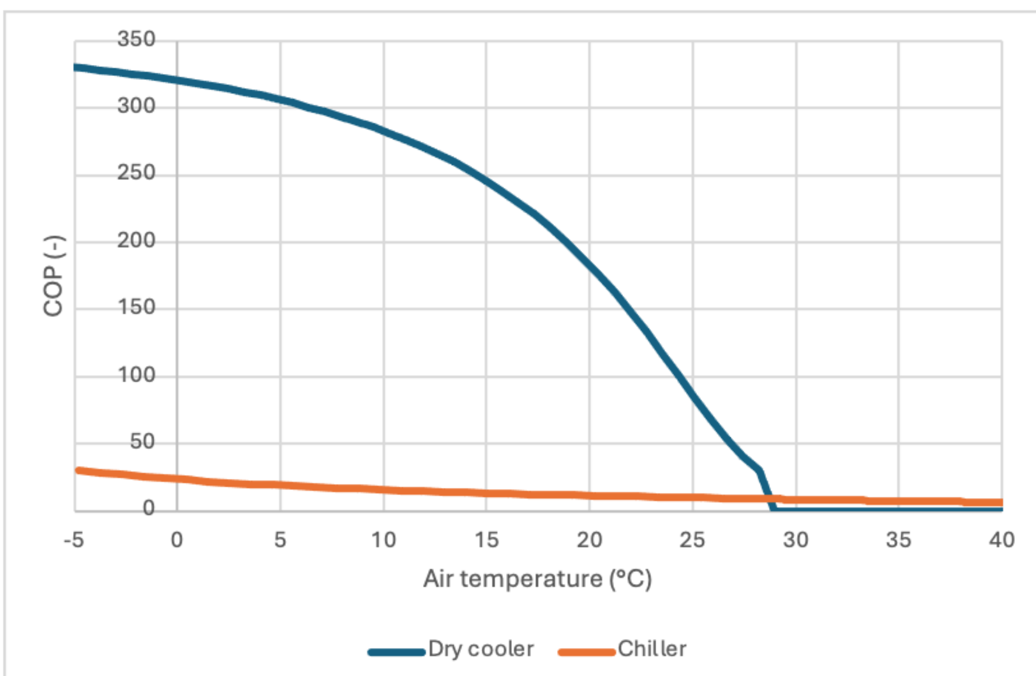

Figure 3: Dry cooler and chiller COP as a function of ambient air temperature, 40°C supply temperature.

RTES is modeled with a simple tank model based on the volume of water in the cold well and is characterized by its storage duration, the ratio of maximum energy storage capacity (MWh) to maximum discharge capacity (MW). Because the RTES hot and cold well temperatures and facilities water system loop mass flow rates are assumed to be fixed, thermal energy balance dictates the relationship between the facilities water system loop temperature difference across the RTES heat exchanger and the RTES loop mass flow rate. The electricity consumption to charge or discharge RTES depends on the RTES loop pump electricity consumption, which depends on the RTES loop mass flow rate, total pressure drop to RTES wells, and the efficiency of RTES well pumps.

We assume that RTES can charge up to 1,000 MW_{th} at any ambient temperature without modifying the chiller or dry cooler COP. In reality, decreasing the chiller or dry cooler output temperature to charge the UTES would decrease the COP and thus increase the power requirements for cooling. Future work will examine this assumption and its impact on the grid value of RTES.

The parameter values used in the cooling system model in this paper are listed in Table 1.

Table 1: Parameter values used in cooling system model.

Value	Unit	Description
40	°C	supply temperature to technical cooling loop from cooling distribution unit
50	°C	input temperature from technical cooling loop to cooling distribution unit
45	°C	input temperature to facilities water system loop from coolant distribution unit
35	°C	supply temperature from facilities water system loop working fluid to coolant distribution unit
5	°C	approach temperature of dry cooler
100	°C	maximum temperature of facilities water system loop working fluid
0	°C	minimum temperature of facilities water system loop working fluid
0.004184	MJ/kg-°C	thermal capacity of facilities water system loop working fluid
0.004184	MJ/kg-°C	thermal capacity of RTES loop working fluid
40	°C	RTES hot well temperature
30	°C	RTES cold well temperature
10	bar	total pressure drop to RTES wells
0.8	-	efficiency of RTES well pumps

2.2 Capacity expansion models

To assess the potential power system impact of adding RTES to data center cooling systems, the cooling system model described in the previous section is incorporated into two capacity expansion models, GenX and ReEDS. These models produce potential future power system designs by minimizing the investment and operational costs of the electricity system. The cooling system model with RTES is incorporated into these models such that the models will see the endogenously determined hourly cooling system electricity demand, which becomes an additional load that the power system must meet. These capacity expansion models optimize the operations of the cooling system and RTES alongside the power system investments and operations to minimize total electricity system costs.

GenX (Bonaldo et al. 2026) is an open-source electricity system capacity expansion model that co-optimizes long-term investment, retirement, and operational decisions for generation, storage, transmission, and demand-side resources. The model is formulated as a linear optimization and enforces physical, operational, resource availability, emissions, and policy constraints, including unit commitment, ramping limits, reserve requirements, and storage dynamics. Here, GenX is solved at hourly resolution using 52 representative weeks drawn from 15 historical weather years to represent interannual variability.

ReEDS (Avraam et al. 2025) is a state-of-the-art capacity expansion model developed at the National Laboratory of the Rockies focused on the evolution of the power system in the contiguous United States. It includes detailed representations of current state and federal policies, such as renewable portfolio standards (RPS) and tax credits, as well as the development potential for a broad range of technologies including new and upgraded hydropower plants, pumped hydropower storage, hydrothermal and enhanced geothermal systems supply curves. To rapidly simulate least-cost power system futures for the contiguous United States through 2050 at state or higher spatial resolution, ReEDS leverages advanced dimensionality reduction techniques, such as optimized representative day selection (Brown et al. 2025).

While GenX and ReEDS are both capacity expansion models, they have some key feature differences listed in Table 2 that impact their results. Both input data and scenario assumptions are harmonized between the two models to ensure any differences in the models' results are due to feature and structural design differences.

Table 2: Key feature differences between GenX and ReEDS capacity expansion models.

Feature	GenX	ReEDS
Temporal resolution	168 hours per week * 52 weeks sampled from 15 weather years (2007-2013, 2015-2023)	8 time chunks per day * 39 representative days taken from 2012 weather year.
Resource adequacy	Enforces capacity reserve margin in every modeled operational hour (capacity in each hour must meet demand plus reserve margin), with dynamic capacity contributions accounting for generator forced outages (as function of temperature) and variable contribution of solar, wind and storage resources during hours with binding reserve constraint.	Enforces capacity reserve margin for winter and summer season (firm capacity in each season must meet peak demand plus reserve margin). Capacity credit of wind, solar, and storage determined uses chronological hourly profiles from 2007-2013 and 2016-2023 weather years. Thermal units use installed capacity (without derate for forced outages).
Unit commitment	Minimum power level, startup fuel consumption and costs, and minimum up/down time constraints are modeled for thermal power plants, but commitment decisions are linearized.	Does not directly model unit commitment for thermal power plants. A fixed minimum generation level is required for nuclear and a linearized startup cost is applied for coal and CCS.
Model planning foresight	No foresight (individual planning stages run in 'myopic' sequence).	No foresight except for state 100% clean energy policies (cost recovery periods for fossil plants shrink as the 100% requirement approaches).
RPS/CES Trading	Assumes RPS/CES credit trading without limits within designated regions (e.g. across PJM).	Allows for RPS/CES credit trading based on technology and region-specific credit trading rules

2.3 Power system input data

Both capacity expansion models use existing generator fleet data from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2025 National Energy Modeling System unit database (EIA 2025a) and their March 2025 Preliminary Monthly Electric Generator Inventory (EIA 2025b). Fuel price projections for gas, coal, and uranium are from the AEO 2025 reference scenario (EIA 2025a) and technology performance and cost projections from the 2024 Annual Technology Baseline, using the moderate case assumptions (NREL 2024). Load growth projections and hourly profiles are from Evolved Energy Research (Jones et al. 2024) and have a 1.8% compound annual growth rate from 2025 to 2050. Wind, solar, and geothermal power generation site-specific resource availability and cost as well as hourly site-specific wind and solar hourly generation potential are from the reV model using the reference siting assumptions (Maclaurin et al. 2021; Lopez et al. 2025).

2.4 Power system scenario

Both capacity expansion models are applied to the same case study to assess the grid impact of RTES for data center cooling. To estimate the value of RTES to the power system given the uncertainty around RTES investment costs, RTES capacity with varying durations was added at no cost.

Both capacity expansion models focused on a shared future scenario, modeling every 5 years through 2050. To ensure sufficient firm capacity to meet future demand, planning reserve margin requirements were enforced based on the NERC 2024 Long-term Resource Assessment (NERC 2025). Current state and federal policies as of August 2025 are included, except for the Clean Air Act regulations for new and existing power plants. While endogenous power plant retirements are allowed, retrofitting fossil power plant with CCS or to burn hydrogen is not allowed, nor is interregional transmission expansion.

To estimate the potential power system savings from RTES, we add 1,000 MW of non-cooling data center electricity load in northern Virginia (more details on the modeled region below). This 1,000 MW of data center load is additional to the data center load projections included in the all-sector demand projections to estimate the grid impact of RTES for a marginal hyperscale data center or cluster of data centers. In the case without RTES, the operation of the data center dry cooler and chiller is optimized as part of the capacity expansion models to minimize grid costs. To estimate the impact of RTES on grid costs, RTES with a thermal discharge capacity to meet all 1,000 MW_{th} of hourly data center cooling load is added to the cooling system. The change in power system costs between the case without RTES and the cases with RTES thus provide an estimate of the value of RTES to the power system.

To investigate the impact of RTES duration on its grid value, RTES cases with 4^*, 8, 12^*, 24^*, 72^*, 168, 1000, and 2000 hours of duration are considered. Durations listed with an asterisk are only considered in ReEDS, while the rest are considered in both GenX and ReEDS. Assuming that the temperature of the subsurface surrounding the RTES wells would stabilize after a few injection cycles, we apply 100%

thermal recovery efficiency. This is consistent with the findings of Pepin et al. (2021) that cold RTES systems in different geologic regions across the contiguous United States have very high thermal recovery efficiencies, with 96.3% to 99.3% recovery after 5 years of operation.

This paper focuses on a case study of the impact of RTES at a large data center in northern Virginia on the PJM power system, a deregulated electricity market that serves most of the mid-Atlantic United States. We model this system with 23 regions, as shown in Figure 4. We add 1,000 MW of non-cooling data center load to the region in northern Virginia (shaded in yellow) and explicitly model the cooling system, with and without RTES, for that load.

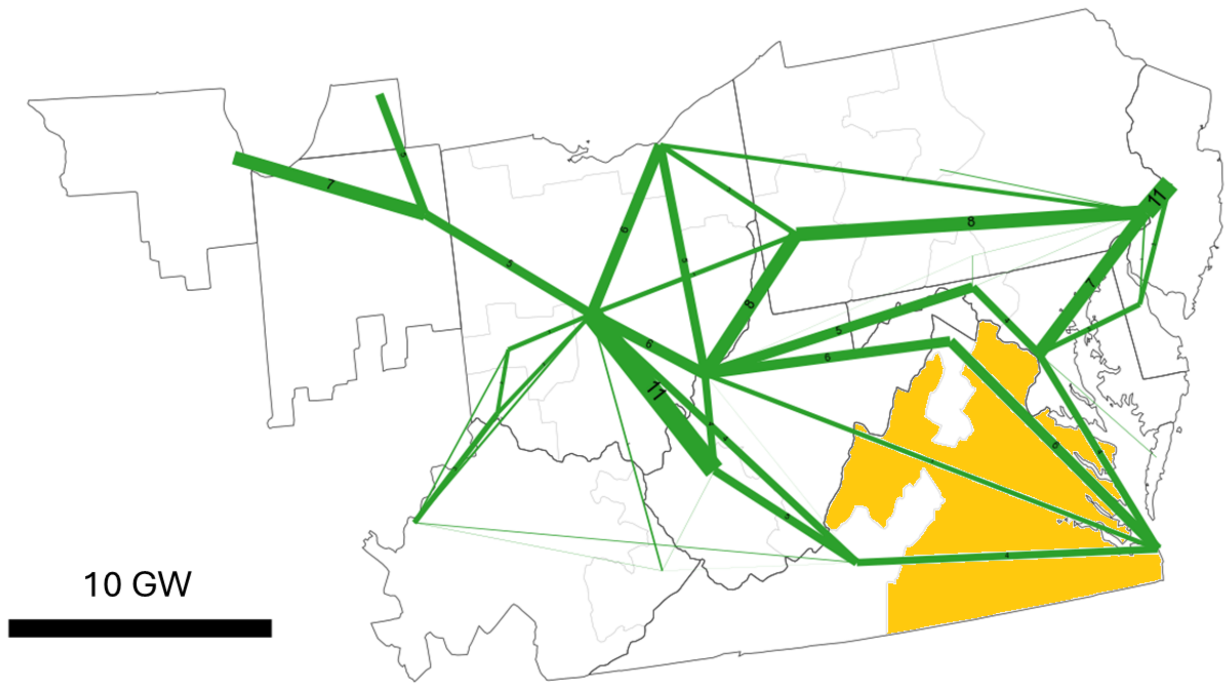

Figure 4: PJM network considered in case study with interregional transmission capacity proportional to width. Additional 1,000 MW of non-cooling data center load with explicitly modeled cooling system located in the region shaded yellow.

We include several Virginia state policies that could have a significant impact on the future of the electricity system. Viriginia requires all fossil fuel plants without carbon capture and storage (CCS) owned by Dominion to retire by 2045. Because ReEDS does not differentiate between utilities, and because Dominion is the largest electric utility in Virginia, we model this mandate by requiring all fossil fuel plants without CCS in the state to retire by 2045. The state also has a renewable portfolio standard and a clean energy standard. Virginia also has an energy storage mandate, with 3,100 MW required by 2035, and an offshore wind capacity requirement with 5,200 MW mandated by the mid-2030s.

3. RESULTS

In this section, we present the results of incorporating a data center cooling system model with RTES into the ReEDS capacity expansion model. Note that at the time of submission, only ReEDS results are available, but we expect to include GenX results in our conference presentation. First, we show the impact of RTES on power system costs in Section 3.1. We then examine the drivers of these cost savings in Section 3.2, which discusses changes in generation and storage capacity investments with RTES.

3.1 Grid cost savings

We find that RTES could offer appreciable power system cost savings to serve new data center load. Adding 1,000 MW of non-cooling data center demand in northern Virginia without RTES in 2030 would add $13 billion in net present value grid costs through 2050 in ReEDS modeling. These grid costs include generation and storage capital expenditures and operations and maintenance costs, fuel costs, and interconnection capital expenditures to connect new generation to the grid. As shown in Figure 5, enabling flexible data center cooling with RTES could decrease the grid cost of adding this data center capacity by $349 to $746 million according to ReEDS modeling, thus reducing the grid cost of serving this data center load by 3 to 6%. Due to the absence of detailed, site-specific RTES cost projections, these figures do not account for the added cost of RTES; however, these bulk power system value estimates could serve as cost targets for RTES developers.

RTES duration has a significant impact on potential grid savings. While increasing RTES duration from 4 to 12 hours increases savings from $349 million to $746 million in ReEDS modeling, savings show diminishing returns from increasing RTES duration above 12 hours of duration, as shown in Figure 5(a). Above 168 hours of duration, duration has minimal impact on cost reductions, as shown in Figure

5(b): increasing duration more than tenfold to 2,000 hours only increases power systems savings by $1 million. While the marginal value of RTES duration is low at longer durations, RTES has a low marginal cost for subsurface energy capacity expansion (McTigue et al. 2023; Raade 2022) that may make large-scale, seasonal storage economical.

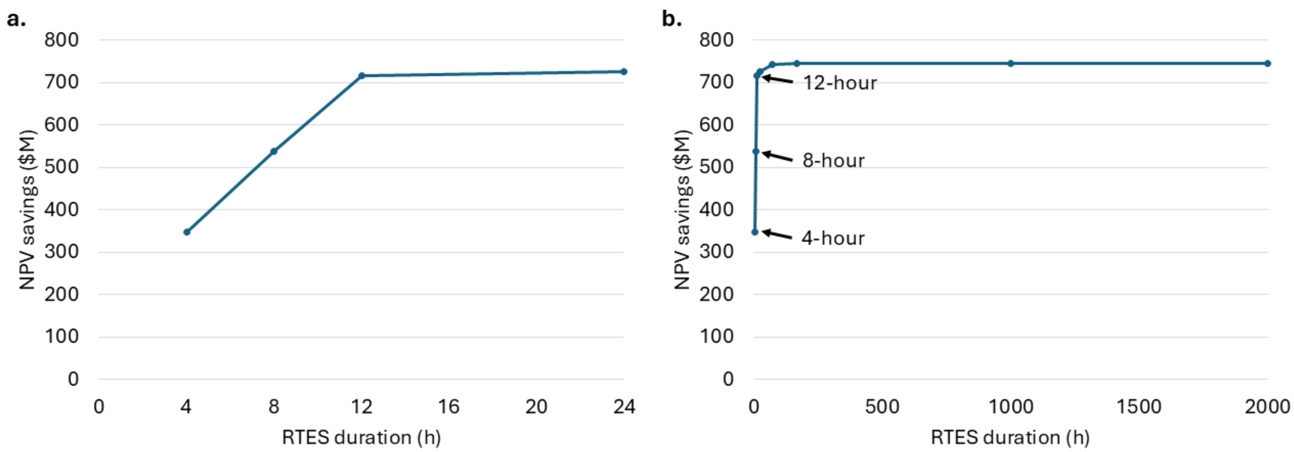

Figure 5: Net present value power system savings from RTES from 2030 to 2050 for a 1 GW$_{th}$ RTES system at varying durations northern Virginia with (a) zoomed x-axis and (b) full x-axis.

Most power system savings from RTES come from reduced generation and storage capital expenditures (capex) in ReEDS, as shown inFigure 6. RTES also lowers generation and storage operations and maintenance (O&M) costs in ReEDS by decreasing capacity. RTES also decreases the investment tax credit (ITC) that the grid receives, which is reflected as an increase in grid cost, by decreasing the capacity of batteries in ReEDS, as discussed in the next section.

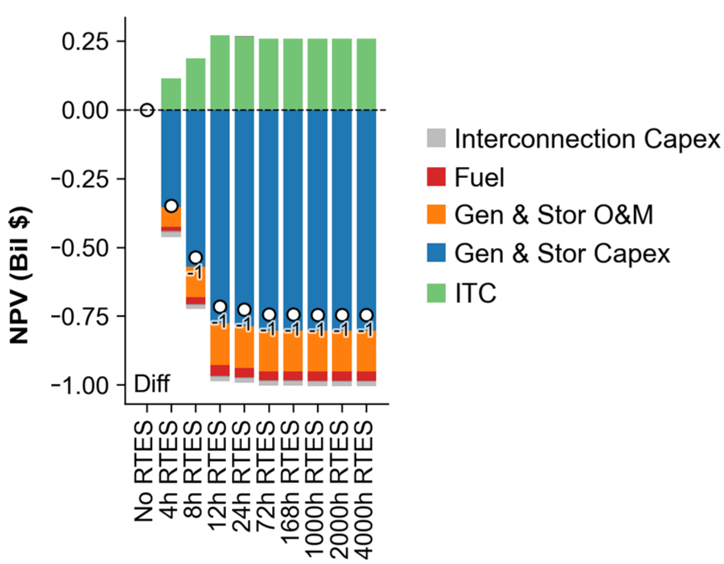

Figure 6: Breakdown of power system cost savings from 2030 to 2050 for a 1 GW$_{th}$ RTES system at varying durations northern Virginia. O&M is operations and maintenance, Capex is capital expenditures, Gen & Stor is generation and storage, CCS is carbon capture and storage, ITC is investment tax credit, and PTC is production tax credit.

3.2 Storage and generation capacity changes

As discussed in the previous section, RTES reduces power system costs to serve new data center load primarily by reducing generation and storage capacity requirements. As shown in Figure 7, for the assumed 1,000 MW non-cooling load data center addition, RTES reduces total installed generation and storage capacity in 2050 by 170 to 200 MW across RTES durations in ReEDS. These capacity changes are significant compared with the 157 MW of peak cooling load for a data center with 1,000 MW of non-cooling load.

At RTES durations over 4 hours, most capacity reductions in 2050 come from firm generation and storage technologies, including hydrogen combined cycle (H2-CC) and batteries[1]. This decrease in firm capacity comes because RTES reduces net peak load, which determines the quantity of firm capacity necessary to meet resource adequacy requirements. These capacity reductions are partially offset by capacity increases primarily in gas combined cycle with CCS capacity (Gas-CC-CCS). Gas-CC-CCS has higher capacity costs but lower fuel costs (and a comparable heat rate) compared to H2-CC, making it more economic than H2-CC to run at high capacity factors when RTES has reduced net peak load and firm capacity requirements.

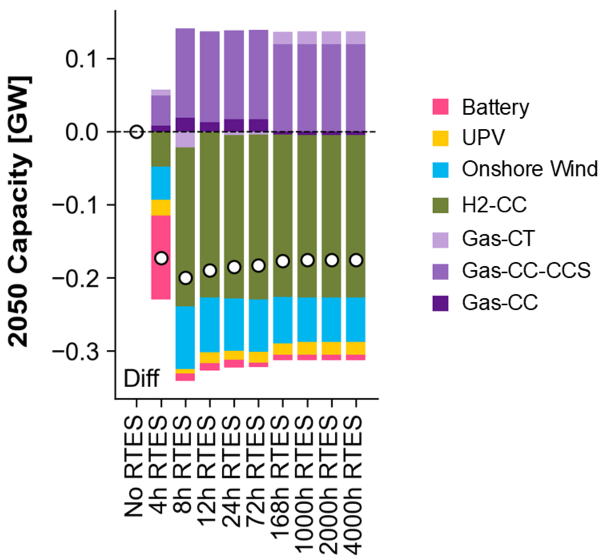

Figure 7: Change in capacity in PJM in 2050 with RTES of varying durations added to data center in northern Virginia. UPV is utility-scale photovoltaics, H2-CC is hydrogen combined-cycle, Gas-CT is gas combustion turbine, Gas-CC-CCS is gas combined-cycle with carbon capture and storage, and Gas-CC is gas combined-cycle.

4. CONCLUSION

This paper estimates the benefit to the power system of incorporating RTES into data centers to enable flexible cooling demand. Incorporating a data center cooling system model into capacity expansion models, we evaluate the impact of RTES on future grid development for a case study in northern Virginia. Adding 1,000 MW of non-cooling data center demand in this region without RTES in 2030 adds $13 billion in net present value grid costs through 2050.

We find that RTES could reduce the grid cost of adding 1,000 MW of non-cooling data center demand in northern Virginia by 3% to 6%. These grid savings are primarily achieved by reducing capital expenditures on generation and storage. In Virginia, RTES decreases net peak demand and thus reduces the need for firm capacity, such as batteries and hydrogen turbines, to meet the planning reserve margin. Capacity expansion modeling thus allows us to evaluate the complex response of the power system to widespread RTES deployment in data center cooling systems. In particular, our results indicate that in contexts where net peak demand that drives capacity planning margins occurs during hours with high temperatures when data center chillers are operating, RTES has considerable potential to reduce data center electricity consumption and avoid unnecessary capital expenditures. As a corollary, cases where capacity planning margins are driven by cooler periods (e.g., overnight or winter periods) when data centers can operate on dry chilling, the advantages of RTES are diminished.

The work presented in this paper is part of an ongoing study first presented in Winick et al. (2025). This paper presents preliminary results that we expect to be indicative of overall trends in the grid value of RTES, but detailed results are subject to change as we refine our modeling approach. Future work may include detailed representation of COP and charging limitations provided by our colleagues focused on detailed, component-level thermodynamic modeling of the cooling system.

ACKNOWLEDGEMENTS

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[1] Note that ReEDS models Virgina's mandate for Dominion to retire all fossil fuel plants without CCS by 2045 as a requirement for all such plants in the state to retire by that date, so they cannot contribute to firm capacity in Virginia in 2050.

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