Evaluating Wind-Following and Ecosystem Services for Hydroelectric Dams in PJM

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ABSTRACT

Hydropower can provide inexpensive, flexible fill-in power to compensate for intermittent renewable generation. Policies for hydropower dams maintain multiple services beyond electric generation, including environmental protection, flood control and recreation. We model the decision of a hydroelectric generator to shift some of its power production capacity away from the day-ahead energy market into a "wind-following" service that smoothes the intermittent production of wind turbines. Offering such a service imposes both private and social opportunity costs. Since fluctuations in wind energy output are not perfectly correlated with day-ahead energy prices, a wind-following service will necessarily affect generator revenues. Seasonal wind patterns produce conflicts with the goal of managing rivers for "ecosystem services" – the maintenance or enhancement of downstream ecosystems. We illustrate our decision model using the Kerr Dam in Pennsylvania-New Jersey-Maryland Interconnection's (PJM) territory in North Carolina. We simulate the operation of Kerr Dam over a three-year period that features hydrologic variability from normal water years to extreme drought conditions. We use an optimization framework to estimate reservation prices for Kerr Dam offering wind-following services in the PJM market. Wind-following may be profitable for Kerr Dam at low capacity levels during some time periods if ecosystems services are neglected and if side payments, or reserves-type payments, are provided. Wind-following with ecosystem services yields revenue losses that typically cannot be recovered with reserves market payments. Water release patterns are inconsistent with ecosystem-services goals when Kerr Dam dedicates significant capacity to wind-following, particularly in drought years.

1. Introduction

As part of a regulatory push to increase the use of renewable resources in electricity generation and to reduce the environmental footprint associated with electric power generation, policies that subsidize or provide incentives for renewable energy investment have become prominent in the state and federal regulatory environment within the United States. The U.S. federal government, for example, provides subsidies in the form of production tax credits and loan guarantees. Individual states have implemented so-called "Renewable Portfolio Standards" (RPS), which set specific targets for investment in renewable or alternative generation sources. An RPS involves a policy at the state level that requires a specific amount of generation from renewable generators by a set timeframe.[1] Production of electricity from renewable resources generates Renewable Energy Credits (RECs), which can be sold in over-the-counter markets or can be used directly by utilities to meet RPS requirements. The economic impacts of RPS have been the subject of a number of studies (see, for example, Dobesova et al., 2005; Apt et al., 2007; Fischer, 2010; Blumsack and Xu, 2011), and have remained one of the principal policy drivers for renewable electricity generation in the U.S.

Wind generation is the predominant renewable electricity generation technology (aside from hydroelectricity) in the U.S. today. The generation of electricity from wind turbines produces minimal emissions of any kind, but requires a controllable and responsive service that fills in supply during periods of low wind-energy production in order to maintain reliability and dynamic stability on the transmission network. Our focus in this paper is on the use of hydroelectricity (not pumped-storage hydro, as in Garcia-Gonzalez et al., 2008) to provide this

[1] The majority of U.S. states currently have renewable energy mandates or "goals" (non-binding penetration targets) in place. See http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

balancing service; specifically on the decision by hydroelectric generators to shift capacity from a pre-scheduled "energy" service to a service that is responsive to wind energy fluctuations.

Using hydropower to balance short-term fluctuations in supply and demand (so-called "load following") is not a new idea. With some exceptions for very large hydro facilities, many hydro generators behave as load-followers, adjusting output in response to changes in electricity demand (Denholm et al., 2004; Sioshansi et al., 2009; Sioshansi, 2011; Kern et al., 2011). Our model explores a market scenario where a hydro generator provides fill-in power based on wind generation fluctuations instead of load fluctuations. We refer to this operational practice as "wind following."

Operationally, we model a hydroelectric dam that chooses to provide fill-in power based on the variable output of a collection of wind turbines and offering energy through a day-ahead scheduling market. The coupled wind farm and hydroelectric dam would thus be fully dispatchable by the system operator and able to participate in day-ahead markets, as in Anderson and Cardell (2008).[2] Our specific case study is to model revenue-maximizing decision making for a hydroelectric dam in the Southeastern U.S. selling hydro supplies in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) electricity market. The hydro dam operator can choose to allocate capacity between the PJM day-ahead energy market and a wind-following service that is responsive to changes in wind energy output. We model the dam's decision-making process and annual revenues using historical data from wet to severe drought years.

We find that the utilization of hydroelectricity to provide such a wind-following service would necessarily impose opportunity costs on the owner of the hydroelectric dam since fluctuations in wind energy are anti-correlated with fluctuations in electricity demand. We

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[2] The coupled wind/hydro installation could be ramped-up by the system operator by increasing hydro production during intervals of low wind. The coupled installation could be ramped-down by reducing hydro output or by spilling wind energy.

provide a decision framework with which to assess these opportunity costs, and we find that these opportunity costs are typically lower than the payments that system operators would need to make to facilitate large-scale wind energy integration by utilizing existing ancillary services markets. Only during periods of hydrologic drought do our estimated opportunity costs exceed ancillary services payments if other potentially conflicting water demands are neglected. However, if the dam is asked to satisfy downstream river-flow requirements to support downstream ecosystem quality in addition to the wind-following services policy option (Richer, et al., 1996; Suen and Eheart, 2006; Whisnant et al., 2009; Kern et al., 2011), we find strong conflicts between the policy goals of providing wind-following services and providing services to support the health of vulnerable ecosystems. The reservation price required to induce entry into a wind-following market by hydroelectric generators is highly sensitive to the regulatory regime in which the dam is assumed to operate.

Our results suggest that regulatory adjustments would be necessary to induce generators to provide wind-following services, whether as ancillary services or in the form of an energy fill-in product coupled with a specific wind site or collection of sites. Either construct would necessitate that market prices and payments to suppliers be based on opportunity cost, rather than incremental accounting costs. We find that current ancillary services prices would be compensatory for generators offering wind-following services, but the system costs of large-scale wind integration may be lower if wind generators were required to offer an energy product coupled with a dispatchable resource. We hypothesize that such a policy would also facilitate the inclusion of wind and other renewables into regional system planning processes, although this area is left as a topic for future research. Our results are based on the simulated operation of a hydroelectric dam (since we are also concerned with policy conflicts between energy production and other river management policy objectives) but are qualitatively generalizable to other potential technologies used to back-up wind energy production.

2. The decision to offer fill-in energy for wind farms

A hydroelectric operator participating in a centralized electricity market faces the decision of when to sell electricity into the market (thus passing water from the reservoir through the turbine) and what type of product to sell to the market. Generators selling into centralized markets can offer various combinations of energy, capacity and ancillary services such as regulation and operating reserves. The provision of ancillary services generally imposes an operational efficiency penalty on the generator since the generator heat rate varies with the level and time derivative of output (for an example, see Katzenstein and Apt, 2009). Hydroelectric facilities are particularly advantageous for providing ancillary services due to their fast ramping rates and low efficiency penalty.

Our focus in this paper is on the decision to offer energy through a day-ahead scheduling market versus offering a wind-following product that provides the market with ramp-up and ramp-down services in response to fluctuations in wind energy output. The basic profit-maximization problem for a hydroelectric generator offering energy services during a period ($t = 0,\ldots,T$) is taken from Horsley and Wrobel (1999) and Perekhodtsev (2003):

(1) $$\max_{y_t} \prod = \sum_{t=0}^{T} y_t p_t$$

subject to the following constraints 2-4:

(2) $$0 \leq y_t \leq y_{max}$$

(3) $s_{min,t} \leq s_t \leq s_{max,t}$

(4) $s_T = s^*$

In the maximization problem, y_t is the energy output at time t, sold into the market at price p_t. The marginal costs of producing hydroelectricity are low, so these are neglected in the problem formulation. The variable s_t is the level of the reservoir behind the dam, which must be kept within the bounds (s_{min}, s_{max}). The hydro operator must adjust flows through the dam to meet a target level s^* at the end of the period (time T). The reservoir constraints are collectively referred to as the *guide curve* for the hydroelectric dam operator.[3] Guide curves are typically set to achieve a number of objectives, including energy production, recreation, and ecosystem services.

If the prices p_t are deterministic, then the solution to the hydroelectric generator's maximization problem is to supply electricity to the market during the highest-priced hours (Perekhodtsev, 2003). To provide wind-following services to the market, the generator specifies a portion of its production capacity $y_{rescap} \leq y_{max}$ that is removed from the day-ahead energy market and utilized for the wind-following service. This capacity allocation between the wind-following and energy services represents a commitment on the part of the generator in advance of real-time dispatch. The actual wind-following energy $y_{res,t}$ produced by this slice of the generator's capacity is determined not by the generator's energy supply offer but in response to a system signal w_t. Thus, this portion of the generator's output is governed by:

(5) $\frac{dy_{res}}{dt} = -\gamma \frac{dw}{dt}$

[3] We follow Horsley and Wrobel (1999) and Perekhodtsev (2003) in modeling the guide curve as a hard constraint. Kern, et al (2011) note that some deviations from the guide curve are observed in practice.

The constant of proportionality γ indicates the contribution of the generator to offsetting the system fluctuation *dw/dt*. The specific system fluctuation that we study in this paper corresponds to changes in wind energy output.[4]

The wind-following service that we describe in this paper does not currently exist in PJM or any other U.S. Regional Transmission Organization (RTO), and one of the goals of this paper is to evaluate the economic incentives necessary for individual generators to participate in such a market. Mount, et al. (2011) have also argued that RTOs will need to establish separate markets and prices for wind integration services.[5] In our model, wind-following services could be provided in the form of "fill-in" power offered to the day-ahead or real-time market (in which case they would be paid the day-ahead or real-time price for each MWh of fill-in energy provided), or generators could offer capacity to a wind-following reserves type of market. Generators providing reserve capacity earn a reservation price p_{rescap} for the capacity (MW) removed from the energy market to be dispatched as reserves. For the amount of energy actually produced (MWh), generators are paid the real-time energy price p_t. The optimization problem for a generator providing both energy and reserves to the market is thus:

(6) $$\max_{y_{energycapt,t}, y_t, y_{rescapt,t}} \Pi = \sum_{t=0}^{T} y_t p_t + y_{res,t} p_t + y_{rescap,t} p_{rescap,t}$$

subject to the following constraints 7-12:

(7) $$y_{res,t} = f(w_t)$$

[4] The wind-following ancillary services signal may be a function of the wind forecast error rather than a function of wind variability in and of itself. We do not have data on wind forecast errors, so we use variations in wind energy output as a proxy. Time-series studies of wind forecast error such as de Mello, et al. (2011) have found that the variability in forecast error is comparable to the variability of wind energy output itself.

[5] Mount, et al. (2011) focus on providing ramp-up and ramp-down services on the demand side of the market, while our focus is the supply side. A portfolio of demand-side and supply-side resources will likely be necessary to integrate large amounts of wind energy without degrading system reliability (Apt, 2007, also makes this observation).

(8) $y_{energycap,t} = y_{max} - y_{rescap,t}$

(9) $0 \leq y_t \leq y_{energycap,t}$ (μ_t)

(10) $0 \leq y_{res,t} \leq y_{rescap,t}$ (η_t)

(11) $s_{min,t} \leq s_t \leq s_{max,t}$

(12) $s_T = s^*$

Equation 7 indicates that reserve energy (MWh) produced by the generator is not a decision variable, but is rather a function of the system signal w_t. Equation 8 indicates that the generator's capacity must be completely allocated between the energy market and the reserves market. The amount sold into the energy market cannot exceed $y_{energycap}$ (equation 9) and the amount of electrical energy produced through the reserves market cannot exceed y_{rescap} (equation 10). Note that if the portion of the generator's capacity dedicated to providing reserves is utilized during the same time *t* that the generator would elect to schedule delivery into the energy market, then the generator would be indifferent between offering energy and reserves, and the optimal reservation price p_{rescap} would be zero.

The Lagrange multipliers μ_t and η_t indicate the marginal opportunity cost of committing to an allocation (y_{rescap}, $y_{energycap}$) when a re-allocation towards one or the other of the two markets would have been more profitable. These multipliers are thus the shadow cost of capacity commitment to one market versus another. For example, if dw_t/dt is very small during a period of high prices, then the generator would have ex-post preferred to re-allocate capacity away from the wind-following service. This sort of ex-post re-allocation is typically not permitted in centralized electricity markets, due to the need to pre-schedule both energy and reserves. The scenario analysis performed in this research estimates these Lagrange multipliers over a range of operational set-points that yield different revenue streams and costs when capacity is allocated between energy and wind-following services.

Whether wind-following services are offered as fill-in power through the energy markets or offered as ancillary services, we define the total opportunity cost (OC) arising from the allocation of y_{rescap} to providing wind-following services, versus not offering these services as:[6]

(13) $$OC = \prod{}_{y_{rescap=0}} - \prod{}_{y_{rescap>0}}$$

Based on the generator's optimization problem, it is clear that as the correlation between energy market prices and w_t declines, the opportunity cost of providing reserves services increases and a larger payment p_{rescap} is necessary to provide incentives for generators to offer wind-following services to the system operator.

3. Roanoke River Basin case study

As a case study for examining properties of a wind-following reserves product in centralized electricity markets, we examine a small hydroelectric power producer in the Roanoke River Basin (RRB), located in the Southeastern U.S. The RRB possesses three dams that lie in series: Kerr, Gaston and Roanoke Rapids, ultimately controlling outflow to the downstream Hardwood Bottomland Forest ecosystem. This forestland houses protected aquatic and terrestrial wildlife

[6] We use the term "opportunity cost" differently than it is used in the context of PJM's ancillary services market. Our concept of opportunity cost refers to the difference in total generator revenues arising from allocating some amount of capacity to wind-following versus an operational practice of offering only into the day-ahead or real-time energy markets, as in Kern, et al. (2011). One of our goals in this paper is to determine the reservation price for wind-following capacity or energy that would be required to induce entry into a market for wind-following services.

and plant species in which the state of North Carolina has invested more than $40 million in conservation efforts (Whisnant et al., 2009). Preserving downstream environmental quality in the face of hydrologic fluctuations is an additional regulatory objective in the operations of dams on the Roanoke River.

We focus in particular on the operation of Kerr dam, which is owned by the U.S. Army Corps of Engineers but operated by Dominion Energy. Kerr Dam sells electricity into the PJM market, and Dominion also wheels energy from Kerr or the broader PJM market to local electric distribution companies in North Carolina known as “preference utilities.” The preference utilities lie outside PJM’s territory and have been allocated property rights to the output of Kerr Dam at low rates (see Section 4.2). Thus, multiple stakeholders influence Kerr Dam’s operation and profits. Kerr is responsible for flood control, recreation, municipal supply, hydroelectricity generation, and ecosystem services.

Power production decisions at Kerr Dam are made on a weekly basis, and are the result of a multi-step communication chain. Each Wednesday, the United States Corps of Engineers (USACE) determines a weekly water declaration for the volume of water to be released from the Kerr reservoir, which is sent to the Southeastern Power Administration (SEPA). The water release declaration can also be expressed in a weekly energy declaration (MWh). In parallel, the preference utilities submit a delivery schedule to SEPA that specifies when they are to receive electricity wheeled from Dominion at the subsidized rate. Dominion is responsible for wheeling power to the preference utilities according to their declared schedules, but can draw either on Kerr Dam or the PJM spot market to fill the preference utilities requests. Thus, the operation of Kerr Dam does not always physically follow the schedules set by the preference utilities.

4. Model description

4.1 Scenario analysis description

We model operational decisions at Kerr dam, the decisions of preference utilities regarding their allocation of low-cost energy from Kerr dam, and the resulting pattern of power production, river flows and energy-market revenues under three scenarios (figure 1). The first scenario called 'business-as-usual' (BAU) uses historical hydropower production data from Kerr Dam. Our other two scenarios are benchmarked against this BAU scenario. The second scenario or 'wind-following' uses a linear program to determine the timing and amount of power production that maximizes annual revenue for Kerr dam by supplying hydropower to the day-ahead and synchronized reserves market. The third scenario builds from the previous two by offering generation through the day-ahead and ancillary services market, but also meets storage and release targets that benefit the downstream ecosystem. Thus, we call the third scenario 'wind-following with ecosystem services'.

In all scenarios, Kerr Dam is assumed to be a price-taker in the relevant markets (i.e., we do not assume any strategic timing of releases as in Bushnell, 2003). We also assume that water could be spilled during some hydrologic scenarios (i.e., water is pushed through the spillway when mandated releases are larger than the turbine capacity) but we do not consider scenarios where the system operator "spills" wind by dispatching the wind farm down.

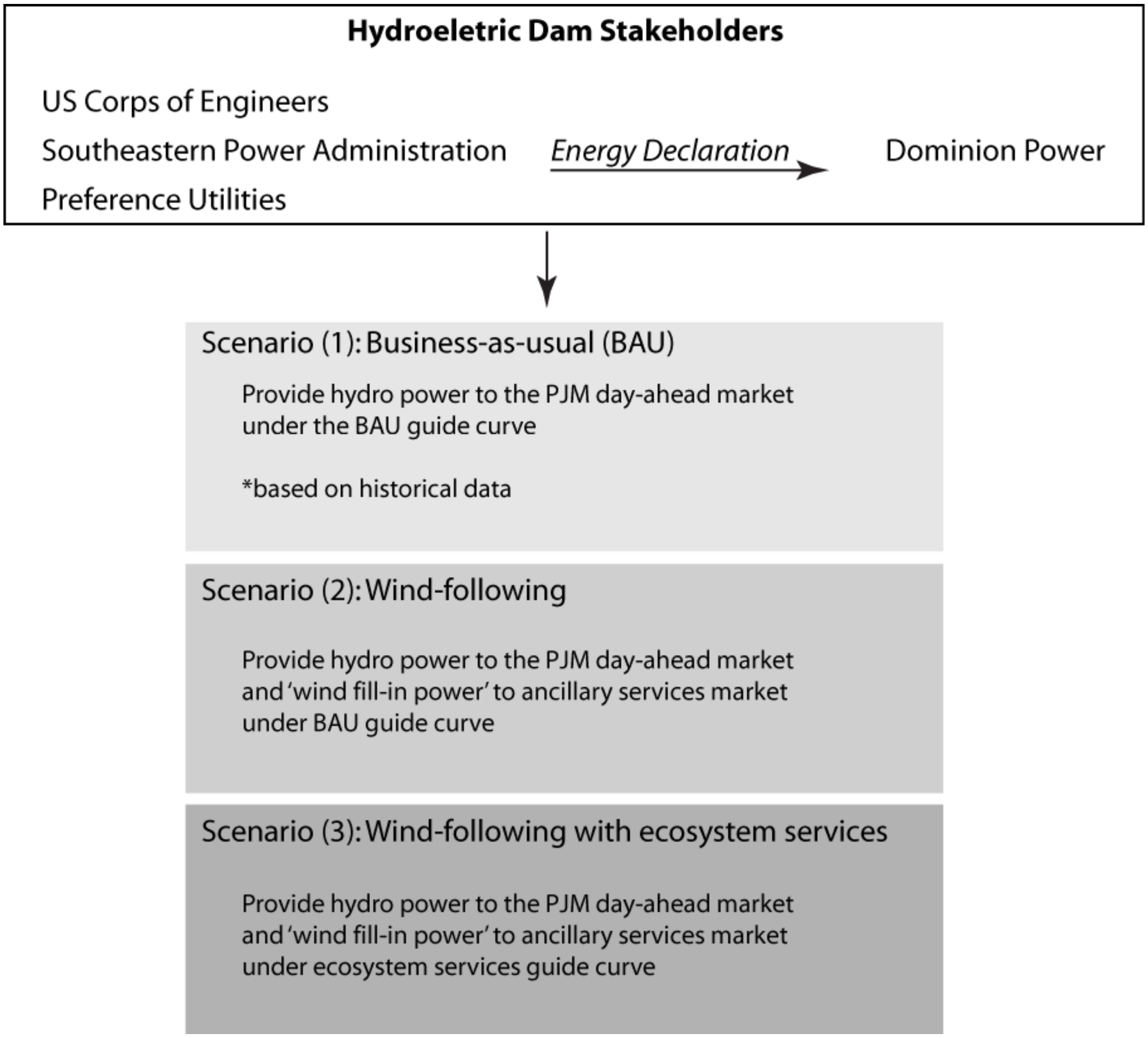

Figure 1. Overview of the stakeholders impacting Kerr Dam operational decisions across energy policy scenarios for Dominion, including the current business-as-usual practices (scenario 1), offering wind-following services (scenario 2) and consideration of both wind-following and ecosystem services (scenario 3).

Historical hydropower output data from Kerr Dam, shown in figure 2, suggests daily and seasonal patterns to energy output decision-making. During the first half of the year, Kerr has one daily peak typically during the evening (see figure 2a) and two peaks during the rest of year that occur in both the morning and the evening (see figure 2b). Model simulations show the optimal allocation to the day-ahead electricity market follows this diurnal pattern.

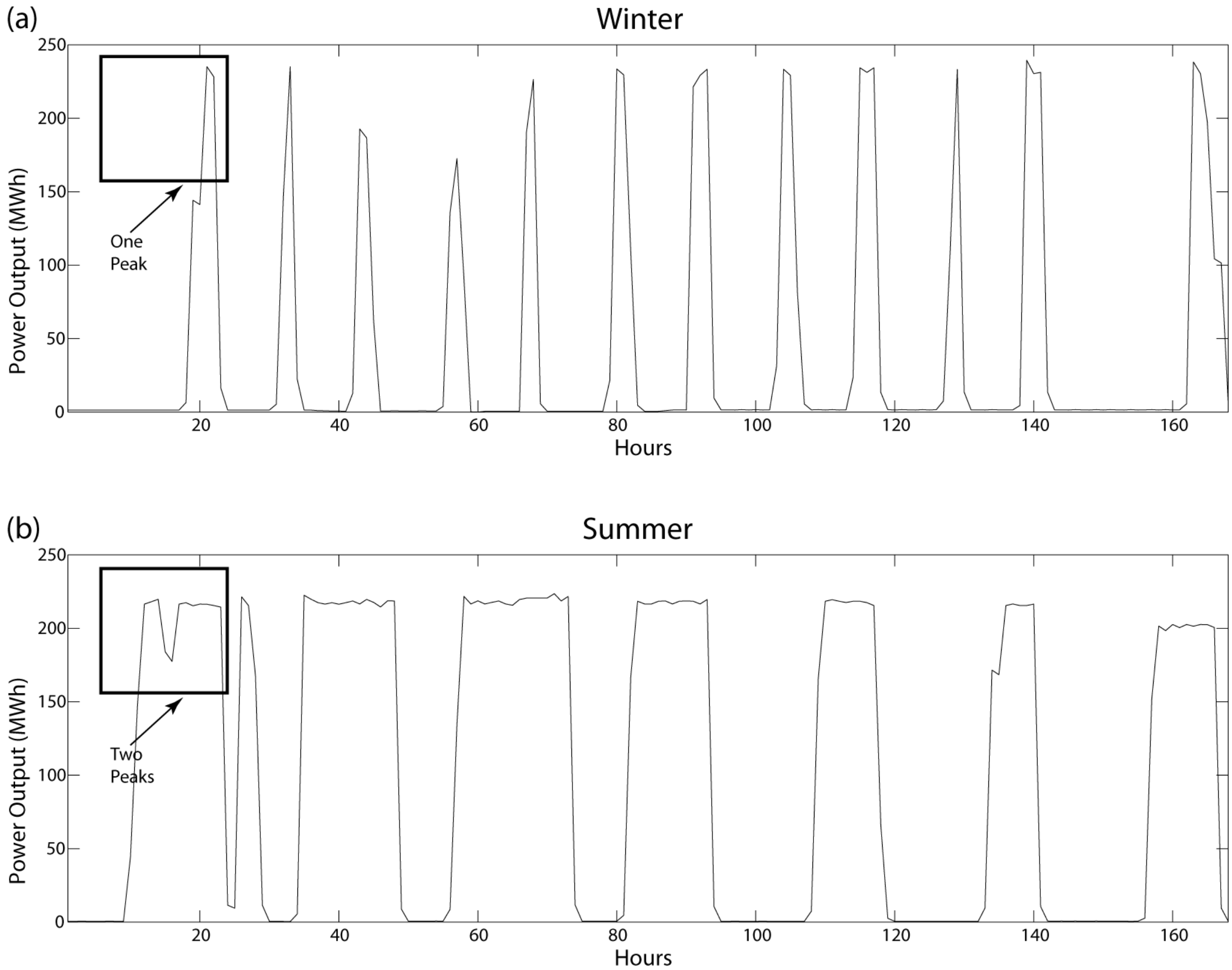

Figure 2. Hourly power output from Kerr Dam during (a) a winter week and (b) a summer week in MWh. Notice the winter days have one daily peak, typically occurring during the evening, and summer days have two peaks, usually one in the morning and the other during the evening.

4.2 Problem formulation

At the start of each model simulation, the preference utilities submit weekly schedules indicating the hours when they would like to purchase electricity at the subsidized rate. A total of seventy-six preference utilities exist in the Dominion zone (North Carolina and Virginia). Although each of the preference utilities is an independent entity, we model them as a collective group that solves a single optimization problem, namely to minimize the cost of meeting their customers' electricity demands. The preference utilities can use three supply sources:

Option 1: Power can be purchased from the PJM spot market ($y_{PJM,t}$) at price $p_{PJM,t}$. We assume that preference utilities are price-takers in the PJM market.

Option 2: Power can be self-generated from resources owned by the preference utilities ($y_{SG,t}$) We set $y_{SG,t}$ to be $80.66/MWh, representing an average of delivered natural gas price of $10.00 per thousand cubic feet, delivered No. 6 fuel oil price of $2.12 per gallon and marginal cost of hydroelectricity of $10/MWh (EIA, Natural Gas Prices, 2010; EIA, No. 2 Distillate Prices, 2010; Newcomer et al., 2008; Newcomer and Apt, 2009).

Option 3: Preference utilities can schedule delivery from Kerr Dam at the subsidized price of $8.25/MWh (Kern et al., 2011). The optimization problem for the preference utilities is thus:

(14) $$min\ Cost_{y_{PJM,t},y_{SG,t},y_{SEPA,t}} = \sum_{t=1}^{T} p_{PJM,t} \times\ y_{PJM,t}\ + 80.66 \times y_{SG,t} + 8.25 \times y_{SEPA,t}$$

subject to the following constraints 15-18:

(15) $$\sum_{t=1}^{T} y_{PJM,t}\ + y_{SG,t} + y_{SEPA,t} = Load_t$$

(16) $$y_{SEPA,t} \leq 204\ MW$$

(17) $$\sum_{t=1}^{T} y_{SEPA,t} \leq\ Weekly\ BAU\ Declaration$$

(18) $$y_{SG,t} \leq\ \ y_{SG\ max}$$

In equations 15 through 18, *Load*$_t$ is the total preference utility electricity demand during hour *t*, and *Weekly BAU Declaration* is the weekly energy declaration at Kerr Dam under current BAU operations, which determines the amount of low-cost electricity available to the preference customers on a weekly basis. Equation 15 says that the preference utilities must meet customer demands during each hour through a combination of PJM spot market purchases, self-generation, and subsidized energy from Kerr Dam. Equation 16 is the capacity constraint on Kerr Dam. Equations 17 and 18 define the total weekly amount of subsidized energy available from Kerr Dam, and the capacity constraint on self-generation of 9.08 MW during each hour *t*.[7]

Dominion's revenues depend on the differential between the fixed SEPA rate p_S and the hourly expected price p_M as well as the amount of generation sold to the preference utilities and PJM. If prices in the PJM wholesale market drop below SEPA's fixed rate during hours when the preference utilities request delivery of generation from Kerr Dam, Dominion earns increased revenues $(p_s - p_M)$. Similarly, if PJM prices are higher than the SEPA fixed rate, then Dominion loses money ($p_M - p_S$) during hours when it must wheel power to the preference utilities. Thus, the scheduling decisions by the preference customers influence Dominion's revenues but not operations at Kerr dam (since Dominion can always wheel power to the preference utilities from the broader PJM market).[8]

The BAU scenario is based on historical data from Kerr Dam. We assume that Dominion operates Kerr Dam so as to maximize revenues. We use historical output data from Kerr Dam and price data from PJM to calculate BAU revenues, as shown in equation 19 for an arbitrary time horizon $t = (1, \ldots, T)$.

$$(19) \qquad BAU\ Rev_t = \sum_{t=1}^{T} \left(p_{S,t} - p_{PJM,t}\right) \times y_{SEPA,t} + p_{PJM,t} \times y_{PJM,t}$$

[7] Data regarding self-generation capacity was collected through telephone interviews with the preference utilities.

[8] Prior to Dominion joining PJM in 2005, the *physical* scheduling of power output at Kerr dam followed requests by preference utilities to have power wheeled from Kerr at the SEPA rate (Whisnant et al., 2009).

The second scenario optimizes revenues with a wind-following constraint. Under this scenario, the dam allocates some amount of its capacity (up to 100 MW) to balancing output fluctuations from a collection of wind turbines in the Allegheny Mountains near the Virginia/West Virginia border (NREL, 2010).

In our initial simulations of Kerr Dam's capacity allocation problem, we found that dedicating capacity to wind-following resulted in frequent violations of the guide curve under all hydrological and policy scenarios. This result is interesting in and of itself, as it suggests fundamental conflicts between usage of the river system to achieve renewable energy goals and river-system management goals related to other energy production, recreation and downstream ecosystem health. For the purposes of examining the financial trade-offs faced by Kerr Dam related to the decision to provide wind-following services, we include in Kerr Dam's objective function a revenue penalty of $1,000/MWh that applies if the hourly output exceeds the hourly energy declaration. This penalty factor is consistent with other penalty-factor formulations in the power systems literature (Zerriffi, et al., 2005; Blumsack et al., 2007).

Equation 20 shows Dominion's optimization problem under the wind-following scenario to maximize revenues over an arbitrary time horizon, assuming that y_{rescap} = 100 MW.

(20) $$\max_{y_{PJM,t}, y_{WIND,t}} WF\ Rev_t = \sum_{t=1}^{T} (p_{PJM,t} \times y_{PJM,t}) + (p_{PJM,t} \times y_{WIND,t}) - \alpha \times (y_{PJM,t} + y_{WIND,t} - Hourly\ BAU\ Declaration_t) + (p_{S,t} - p_{PJM,t}) \times y_{SEPA,t}$$

subject to the following constraints (21) –(25):

(21) $$y_{PJM,t} + y_{WIND,t} \leq y_{max}$$

(22) $$\sum_{t=1}^{T} y_{PJM,t} + y_{WIND,t} \leq Monthly\ BAU\ Declaration$$

(23) $y_{WIND,t} \leq 100 - y_{CAPWIND,t}$

(24) $y_{PJM,t} \leq y_{max} - 100$

(25) $y_{WIND,t} \leq 100$

Constraint (21) allocates the turbine capacity to the day-ahead and wind-following markets, and (22) ensures the monthly power output does not exceed the monthly BAU energy declaration. Constraint (23) ensures that the amount of the reservoir supply dedicated to wind-following at each hour satisfies the amount of wind compensation requested. Constraint (24) is the upper bound that requires at each hour the reservoir supply dedicated to hydropower production is at most approximately 100 MW. Constraint (25) is the upper bound for wind fill-in power being at most 100 MW at each time step.

Lastly, we model a scenario where Kerr Dam offers wind-following services coupled with flow constraints intended to maintain the health of the Hardwood Bottomland forest ecosystem (i.e., the Kerr Ecosystem Management Plan or KEMP). Details of the KEMP guide curve can be found in (Whisnant et al., 2009). Broadly, KEMP would increase required releases from Kerr Dam by as much as 40% (compared to current operations) during the spring and early summer. The model adjusts hydropower production according to the guide curve defined by the KEMP strategy (Whisnant et al., 2009) to consider peak electricity periods and riparian flow levels.

Equation 26 describes the 'wind-following and ecosystem services' objective function with the relevant constraints. During certain times of the year in this scenario, Kerr Dam must spill water to meet release targets; this spilling carries an opportunity cost that we calculate as $p_{PJM,t}$ multiplied by the quantity of foregone power production from $spilling_t$.

(26) $\max_{y_{PJM,t}, y_{WIND,t}} WF\ Eco\ Rev_t = \sum_{t=1}^{T} (p_{PJM,t} \times y_{PJM,t}) + (p_{PJM,t} \times y_{WIND,t}) - \alpha \times (y_{PJM,t} + y_{WIND,t} - Hourly\ Ecosystem\ Services\ Declaration_t) + (p_{S,t} - p_{PJM,t}) \times y_{SEPA,t} - (p_{PJM,t} \times spilling_t)$

subject to constraints 27 – 31:

(27) $y_{PJM,t} + y_{WIND,t} \leq y_{max}$

(28) $\sum_{t=1}^{T} y_{PJM,t} + y_{WIND,t} \leq Monthly\ Ecosystem\ Services\ Declaration$

(29) $y_{WIND,t} = 100 - y_{CAPWIND,t}$

(30) $y_{PJM,t} \leq y_{max} - 100$

(31) $y_{WIND,t} \leq 100$

The system of constraints in this scenario is the same as the wind-following scenario, except for equation 28, which reflects the KEMP release targets.

4.3 Wind data description

The wind profile we use in our analysis is taken from a collection of modeled wind sites along the Allegheny Mountains in West Virginia and Virginia (NREL, 2010) with an annual capacity factor of 0.28. Figures 3 and 4 illustrate the wind profile used in this paper as well as a comparative analysis of wind energy variation and demand variation in the Dominion zone of PJM. The correlation analysis in figure 3 represents the correlation between normalized hourly wind and normalized hourly electricity demand during four seasons (3a-3d). We find that, based on analysis of hourly data, wind and demand are generally anti-correlated, though the nature of the correlation changes seasonally. Wind and demand in the Dominion zone are more highly anti-correlated in the summer than in the winter.

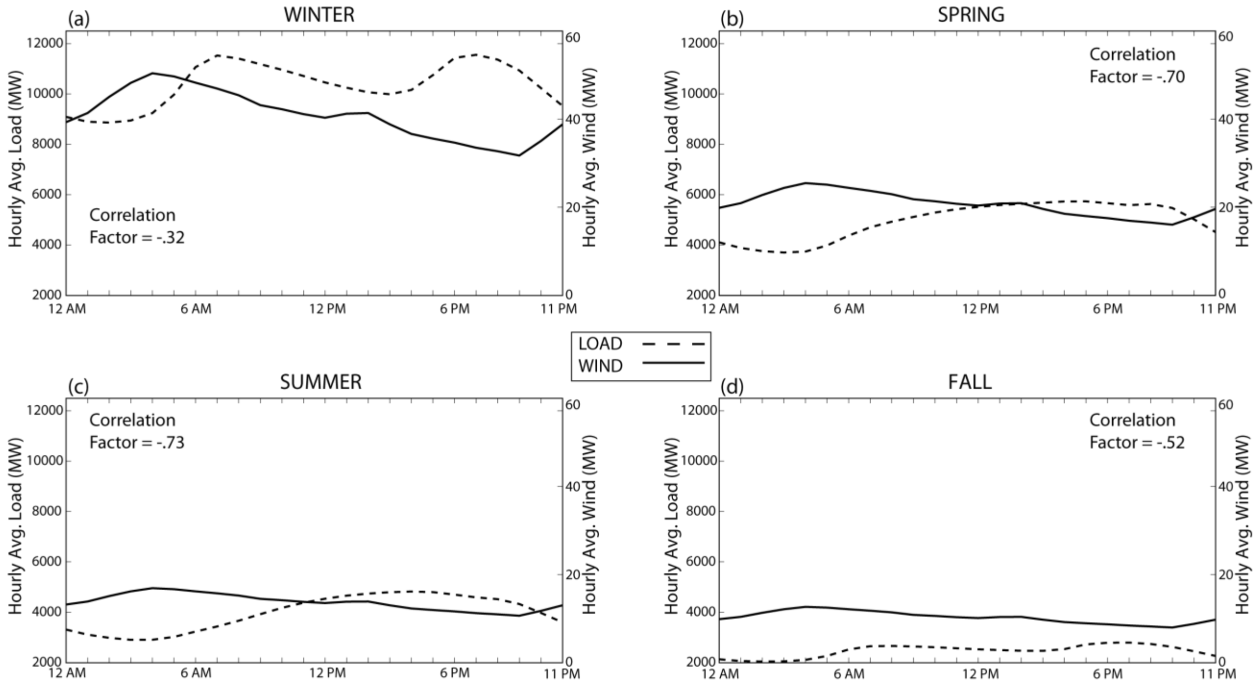

Figure 3.The hourly average load (dashed) and wind power capacity (solid) (MW) during each of the four seasons (a) winter, (b) spring, (c) summer, and (d) fall. Wind profiles are from (NREL, 2010), which includes modeled data based on 2006 meteorological conditions.

Figure 4 shows an annual representation of the normalized hourly wind power output and load in the Dominion zone. Approximately 15% of hourly winds speeds generate up to 35% of the maximum capacity; yet 15% of hourly load demands 45% of maximum capacity. Conversely, approximately 50% of hourly load demands 50% of maximum power capacity where 50% of the hourly wind speeds can generate up to 80% of the maximum capacity.

Taken together, figures 3 and 4 demonstrate that the utilization of Kerr Dam (or any generator for that matter) as a wind-following resource will produce a different schedule of hourly power production as compared to the utilization of Kerr Dam as a load-following resource during daily peak hours (as in figure 2).

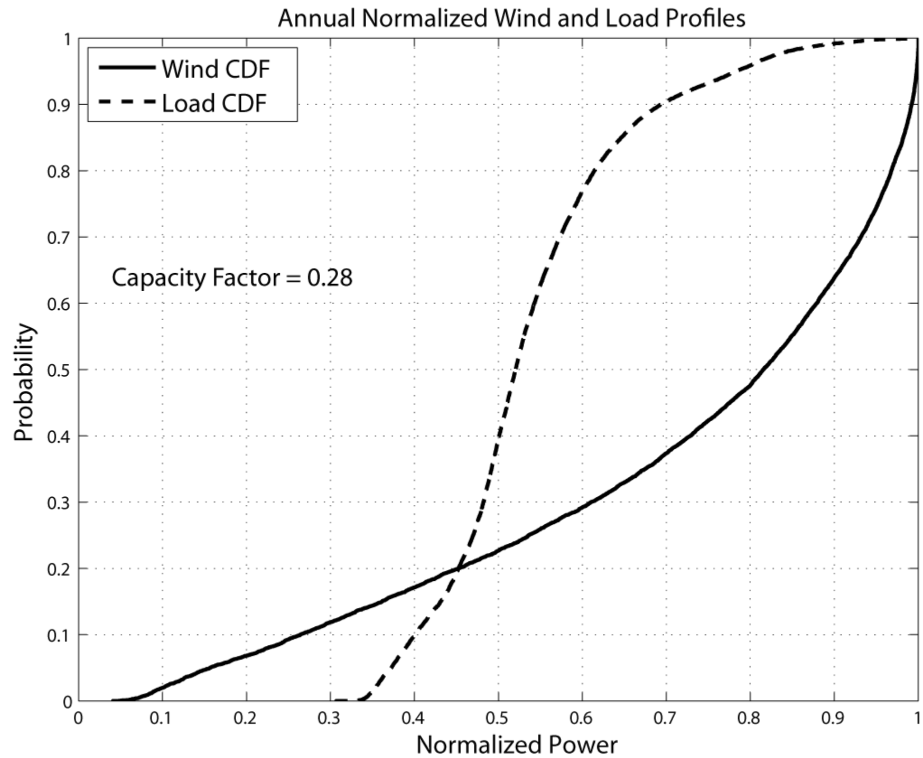

Figure 4. Annual normalized wind power (black solid) and load (black dashed) profiles based on hourly wind and Dominion load data.

5. Results

5.1 The opportunity cost of providing wind-following services at Kerr Dam

We use three metrics to quantify the financial trade-offs between the BAU operations and wind-following with and without ecosystem services for normal (2006) to dry (2008) hydrological years. The BAU scenario provides baseline revenue that we use to compare against wind-following and wind-following with ecosystem services revenue. Opportunity cost is thus defined as the difference between business-as-usual revenues and revenues when Kerr chooses to allocate capacity to a wind-following service. Our primary interest is in the total opportunity cost, as shown in equation 13. We also translate revenues and opportunity costs into average \$/MWh terms so that opportunity costs can be compared directly with energy and reserves market prices. Equations 31-33 show the calculations from percent deviations to (\$/MWh) for each month.

(31) $$WF\ reserves\ payments_t = \sum_{t=1}^{T} WF\ Reserves\ price\ (\frac{\$}{MW})_t \times y_{CAP\ WIND}(MW)_t \times \frac{1}{y_{WIND}(MWh)_t}$$

(32) $$WF\ energy\ payments_t = \sum_{t=1}^{T} \frac{WF\ Energy\ Revenues\ (\$)_t}{y_{WIND}(MWh)_t}$$

(33) $$Opportunity\ Cost_t = \sum_{t=1}^{T} \frac{Opportunity\ Cost\ (\$)_t}{y_{WIND}(MWh)_t} = \sum_{t=1}^{T} \frac{(BAU\ Rev_t - WF\ Rev_t)(\$)_t}{y_{WIND}(MWh)_t}$$

Error! Reference source not found. Figure 5 shows wind-following reserve revenues, wind-following energy revenues and opportunity cost as monthly percent deviations from the BAU revenues for wind-following and wind-following with ecosystem services during 2006-2008. These years represent normal to dry hydrological years as classified by the Palmer Severity Drought Index (PDSI, NCDC 2011), with the data ranging from extremely moist at a PDSI of 6 to extremely dry at a PDSI of -6. Hydroclimatic conditions in 2006 range from normal/wet (3 to 6) to a transition to drier conditions in 2007 (below 0), which ultimately shift to a severe drought in 2008 (-2 to -6). Population pressures and droughts are growing concerns in the Northern Coastal Plain area of North Carolina (Seager et al., 2009, Kern et al., 2011; NCDC, 2011).

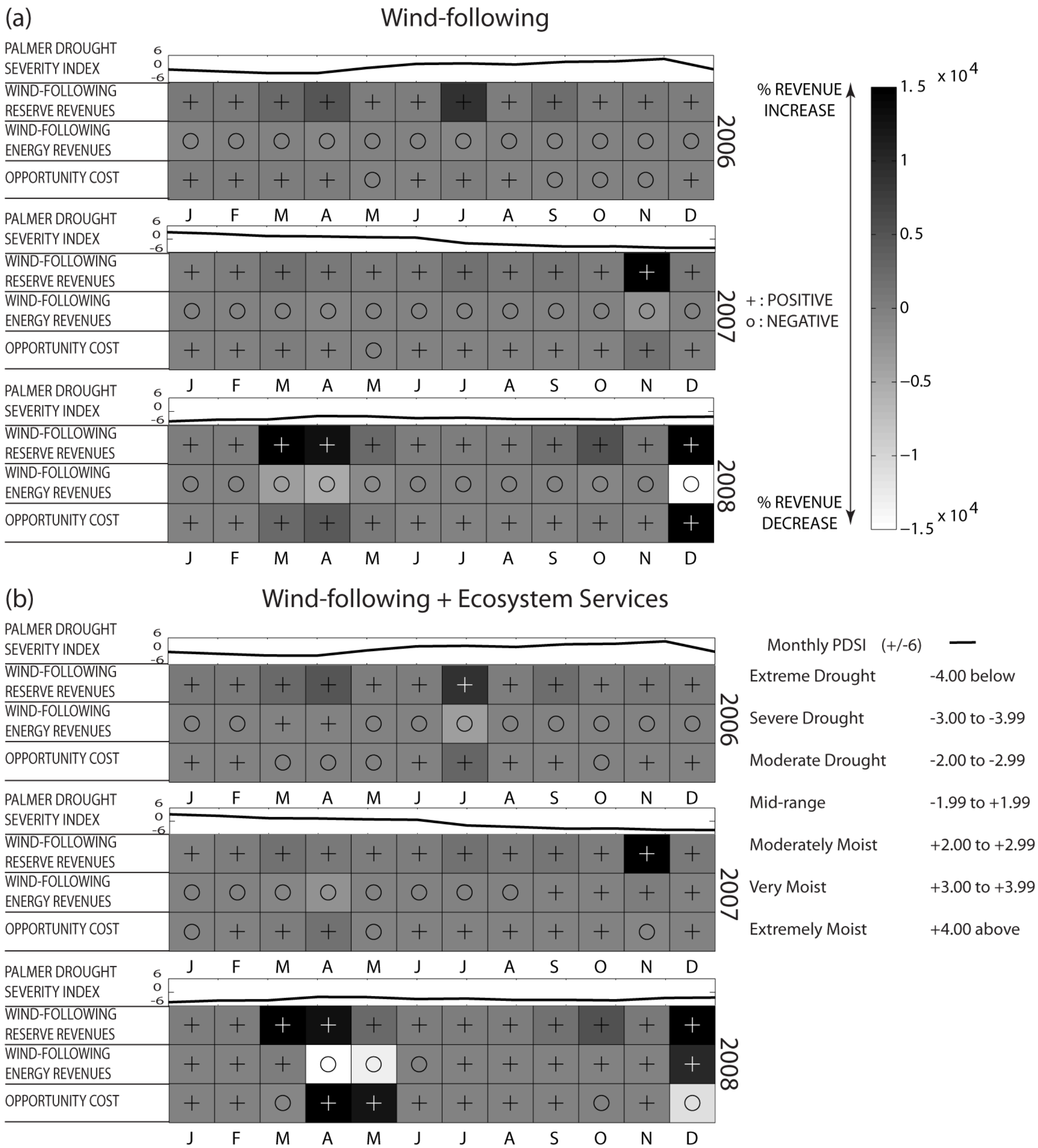

Figure 5. Monthly percentage deviations (from the BAU operations scenario) from 2006-2008 for (a) the wind-following scenario's reserve revenues, energy revenues, and opportunity cost and (b) the wind-following with ecosystem services scenario's performance for the same measures. The full range for percentage deviations is ± 1.17 ×10^5. The plus sign (+) denotes a positive revenue deviation and the (o) denotes a negative revenue deviation. The figure also shows inter-year hydrological variability as captured by PDSI data (NCDC, 2011; NOAA, 2011).

The opportunity cost is directly impacted by hydrologic variability. In figure 5, the shaded boxes show positive (black), negative (white) and neutral (gray) monthly revenue deviations from the BAU scenario. Figure 5a shows that the revenue impacts to Kerr Dam from offering wind-following services vary by month and year, with more extreme monthly revenue impacts in drier years (2007 and 2008). Overall, figure 5 suggests that on a monthly basis, the revenue impacts from wind-following may at times be extreme ($\pm$ 1.17×10^5 percent deviation from the BAU scenario although they are shown below on a range of $\pm$ 1.5×10^4), depending on whether wind-following reserves and energy revenues are accrued in on-peak or off-peak periods. In figure 5b, wind-following with ecosystems services shows negative energy revenues for most all months ranging from moderate (-0.2 percent of BAU revenues) to extreme (-5.2×10^4 percent of BAU revenues) impacts. Large revenue losses (i.e., large opportunity costs relative to BAU operations) may occur when Dominion must sell peak power at a lower rate to the preference utilities (incurring a cost) and may need to provide ancillary services during the day with reduced winds.

Conversely, opportunity cost in wind-following with ecosystem services (figure 5b) is positive for most months, suggesting there is a conflict between providing wind support services and spilling for ecosystem services. A positive opportunity cost also signifies that Dominion would earn more revenues by *not* allocating capacity to a wind-following service and staying in the day-ahead energy market. The positive opportunity costs during the dry summer months in 2007 and 2008 suggest that Dominion allocates less reservoir supply to wind-following services and must also ration water to meet KEMP spilling requirements and minimum downstream river levels for other services (fishing, recreation etc.). April 2008 in figure 5b further shows a large positive opportunity cost, suggesting there is a conflict with meeting the stricter spilling releases during the spawning season (i.e., less hydro power) and providing wind-following. A few winter months in wind-following with ecosystem services show the opposite trend, indicating Dominion would see higher revenues by offering wind-following services and operate under less restrictive spilling requirements.

5.2 Opportunity cost curves for wind-following services

Equation 33 describes the average annual opportunity cost for providing wind-following services; Figure 6 traces out the total annual and average annual opportunity cost (in $ per MWh of wind-following energy provided) of providing wind-following services as the slice of wind-following capacity ranges up to 100 MW. At higher levels of wind-following (without also providing ecosystem services), we see concomitant increases in the opportunity cost to Kerr Dam until the size of the wind-following slice is around 60 MW. The total and annual average opportunity costs are significantly higher when Kerr Dam provides wind-following services in addition to ecosystem services under the KEMP policy. The invariance of total opportunity costs to the level of wind-following provided (figure 6b) suggests that these costs are dominated by persistent violations of the KEMP guide curve (recall that we set a penalty of $1,000 per MWh for each violation), indicating conflicts between the goals of operating the dam for wind-following and ecosystem services. We thus conclude that operating a small-scale hydroelectricity dam like Kerr Dam with hydrological uncertainty may lead to significant opportunity costs when adjusting reservoir releases for the downstream environment (figure 6b).

Figure 7 summarizes an additional sensitivity analysis of the average monthly reserve payments and opportunity cost ($/MWh) with a wind-following range of 1 to 100 MW. In the figure, when the reserve payments (gray bars) exceed the opportunity cost (black dot), Dominion is fully compensated for offering wind-following under the specified policy case. Dominion may elect to provide up to the maximum wind-following capacity at 100 MW under the wind-following policy case and the monthly average opportunity costs do not exceed the reserve payment according to the current ancillary (reserves) services market prices (figure 7a). However, figure 7b shows that wind-following with ecosystem services produces the opposite result with frequent wind-following capacity amounts showing greater opportunity costs than reserve payments.

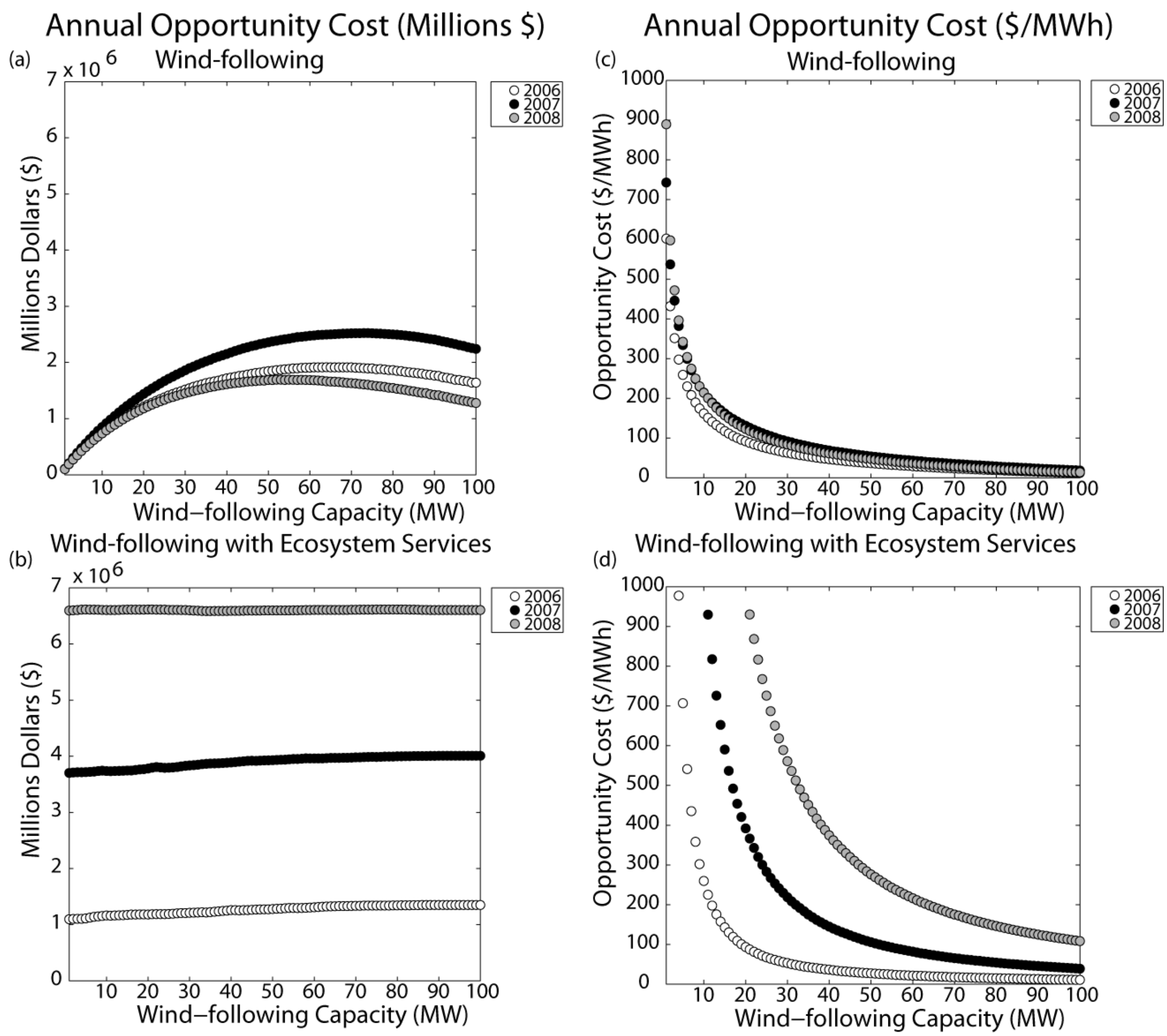

Figure 6. Total annual opportunity cost of providing: (a) wind-following and (b) wind-following with ecosystem services. Average annual opportunity cost of providing each MWh of: (c) wind-following services and (d) wind-following with ecosystem services (full range is 1.0 x 10^5).

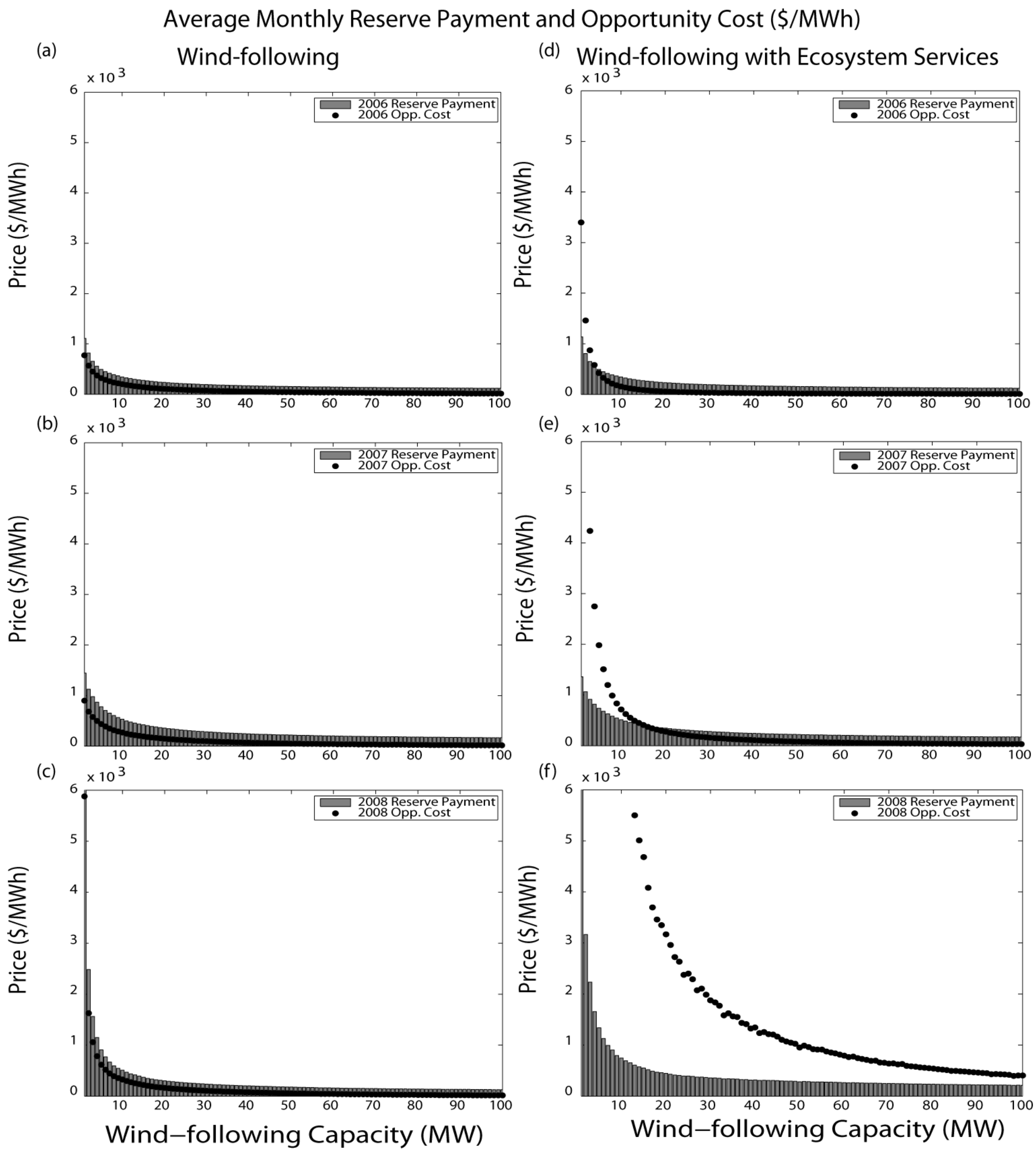

Figure 7. (a-f) Average monthly reserve payments (gray bars) and opportunity cost ($/MWh) for wind-following as a function of the amount of wind-following capacity dedicated by Kerr Dam in (a) 2006, (b) 2007, and (c) 2008. Likewise, wind-following with ecosystem services is presented for (d) 2006, (e) 2007, and (f) 2008. The full range is 1.2×10^4.

The sensitivity analysis also illustrates that reserve payments are greater than the positive opportunity cost with wind-following in 2008, suggesting that wind-following is profitable for Dominion under drought conditions if unconstrained by other demands. Yet, the 2008 results for wind-following with ecosystem services demonstrate the opposite, further supporting the increasingly large, positive annual opportunity costs shown in figure (7b) as Dominion allocates more reservoir capacity into the ancillary services market. Thus, utilizing hydroelectricity to abate wind intermittency becomes a challenge during water-constrained years.

6. Conclusion

Large-scale wind penetration requires the use of flexible resources to fill in during intermittent production periods, posing a challenge to maintain current and future electrical grid reliability standards. Hydroelectric dams possess the physical characteristics (fast ramp-time, large capacity, minimal emissions) to meet system demand and smooth out wind-power fluctuations in a manner consistent with the environmental goals of renewable energy policy. River systems, however, are generally managed to meet many different social objectives. Our analysis has focused on three of these objectives (hydroelectric revenue, facilitating wind integration and maintenance of downstream ecosystem quality). We find that a number of regulatory trade-offs emerge once we alter business-as-usual practices with wind-following and ecosystem services policies.

Our results suggest that regulatory adjustments would be necessary to induce generators to provide wind-following services, whether as ancillary services or in the form of an energy fill-in product coupled with a specific wind site or collection of sites. Either construct would necessitate that market prices and payments to suppliers be based on opportunity cost, rather than incremental accounting costs. We find that current ancillary services prices would be compensatory for generators offering wind-following services, but the system costs of large-scale wind integration may be lower if wind generators were required to offer an energy product coupled with a dispatchable resource. We hypothesize that such a policy would also facilitate the inclusion of wind and other renewables into regional system planning processes, although this area is left as a topic for future research. Our results are based on the simulated operation of a hydroelectric dam (since we are also concerned with policy conflicts between energy production and other river management policy objectives) but are qualitatively generalizable to other potential technologies used to back-up wind energy production.

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