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Low natural gas prices and the financial cost of ramp rate restrictions at hydroelectric dams

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ABSTRACT

Peaking hydroelectric dams that employ variable, stop-start reservoir releases can have adverse impacts on downstream river ecosystems. Efforts to mitigate these impacts have relied predominantly on the use of ramp rate restrictions, which limit the magnitude of hour-to-hour changes in reservoir discharge. Ramp rate restrictions shift hydropower production towards less valuable off-peak hours, imposing a financial penalty on dam owners that is a function of the "spread" (difference) between peak and off-peak electricity prices. This study examines how low natural gas prices in the U.S. have reduced the cost of implementing ramp rate restrictions at dams by narrowing the peak/off-peak price spread. Significantly lower costs of ramp rate restrictions could open new opportunities for improving environmental flows at dams, including the "purchase" of more natural streamflow patterns by downstream stakeholders, a type of arrangement for which there is growing precedent. We also explore the role that uncertainty in the cost of ramp rate restrictions could play in precluding downstream stakeholders from forming these types of agreements with dam owners. Results suggest that financial "collar" contracts could mostly eliminate inter-annual variability in the net cost of restrictions and provide those purchasing more natural flows with greater certainty.

1. Introduction

Optimizing the financial value of hydropower projects relies heavily on the practice of hydropower "peaking," in which dams produce electricity (release water) at maximum rates during high demand hours and release much less water during other, less valuable hours. However, the large hourly fluctuations in river flows that occur as a result of this practice can cause significant environmental impacts downstream, including: habitat loss, altered physicochemical properties, changes in sediment dynamics, stranding of fish and other organisms, and/or the disruption of life cycle processes (Cushman, 1985; Blinn et al., 1995; Freeman et al., 2001; Grand et al., 2006; van Looy et al., 2007). In recent years, efforts in the U.S. to protect rivers from the effects of hydropower peaking have become more widespread, particularly through litigation and the Federal Energy Regulatory Commission's (FERC) dam relicensing process (DeShazo and Freeman, 2005). Jager and Bevelhimer (2007) found that of the 223 dams whose licenses were renewed between 1988 and 2000, 23 (10%) were converted from peaking to "run-of-river" operations, a distinction that means reservoir output is set equal to inflows on a daily and/or hourly basis. Nonetheless, the perceived high value of hydropower as a peaking resource persists as a barrier to restoring natural hourly variability in river flows at other dam sites.

Efforts to restore natural hourly variability in river flows below dams most commonly involve the use of "ramp rate" restrictions, or limits on the magnitude of hour-to-hour changes in reservoir discharge, which force a fraction of total hydropower production to be shifted away from periods of peak electricity demand towards less valuable off-peak hours. The financial penalty that dam owners incur as a result of these restrictions is a function of two factors: 1) the "spread" (difference) between peak and off-peak electricity prices; and 2) the total amount of generation that is shifted from peak to off-peak hours (this amount, in turn, depends on the availability of water for hydropower production) (Edwards et al., 1999; Harpman, 1999; Palmer et al., 2004; Kotchen et al., 2006).

A handful of studies have estimated the annualized financial cost of ramp rate restrictions at different dams in the U.S. and Canada (Harpman, 1999; Kotchen et al., 2006; Jager and Bevelhimer, 2007; Niu and Insley, 2013, 2016; Guisandez et al., 2013). However, with few exceptions (Guisandez et al., 2013; Niu and Insley, 2016) these

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efforts give little consideration to the extent to which the cost of ramp rate restrictions at dams can vary on a year-to-year basis due to fluctuations in the peak/off-peak price spread and reservoir inflows. A more comprehensive understanding of how each of these factors drives changes in the cost of ramp rate restrictions would allow for improved forecasts of these costs to be included in real-time dam/river management, as well as longer-term dam relicensing discussions. Notably, none of these studies address a recent surge in US natural gas production that has important implications for the peak/off-peak price spread in electricity markets and the cost of ramp rate restrictions at dams.

In PJM Interconnection (a wholesale electricity market that covers much of the eastern U.S.) the two main drivers of the peak/off-peak price spread are electricity demand and the price of natural gas. Fig. 1 shows the typical system supply (marginal cost) curve for the PJM day-ahead market, estimated using 2010 EPA eGrid data (EPA, 2015). The system supply curve is broken down by fuel type (color); assumed fossil fuel prices are $10/MMBtu for fuel oil, $5.5/MMBtu for natural gas, and $2/MMBtu for coal. Market (peak and off-peak) prices are determined by the intersection of vertical demand curves with the system supply curve.

Historically, the off-peak price of electricity in PJM has been relatively constant because it is associated with the marginal cost of using electricity from coal plants to meet relatively low demand. Coal prices have historically demonstrated little volatility, and the part of the supply curve associated with coal plants is flat, thus reducing the impacts that year-to-year fluctuations in demand have on off-peak prices. Major fluctuations in the peak/off-peak spread track the peak price of electricity, which is strongly associated with the marginal cost of electricity at natural gas power plants (EIA, 2013). Fig. 1 illustrates how fluctuations in the price of natural gas can alter the marginal cost of electricity at natural gas plants and, as a consequence, impact peak prices and the peak/off-peak price spread in the PJM market. Solid black lines indicate how the contour of the supply curve is changed by natural gas price increases/decreases of $2.5/MMBtu. As the price of natural gas rises and falls, so do the peak price of electricity and the peak/off-peak spread.

In recent years, the combination of improved horizontal drilling techniques and hydraulic fracturing, or "fracking", has led to a surge in domestic U.S. gas production and contributed to an extended period of low natural gas prices (McElroy and Lu, 2013). As a consequence, peak electricity prices and the peak/off peak price spread in PJM have declined, reaching a relative low point in 2012 (a year in which the US also experienced unseasonably mild weather and relatively low electricity demand) (Fig. 2) (NCDC, 2015). A major goal of this research is to determine the extent to which corresponding downward trends in the price of natural gas and the peak/off-peak price spread have reduced the cost of implementing ramp rate restrictions at hydroelectric dams.

If low natural gas prices persist over many years, it could open new, less expensive opportunities for improving environmental flows at dams. A number of previous studies have shown that consumers' willingness-to-pay for more environmentally friendly practices at hydroelectric dams depends on cost and the relative importance of

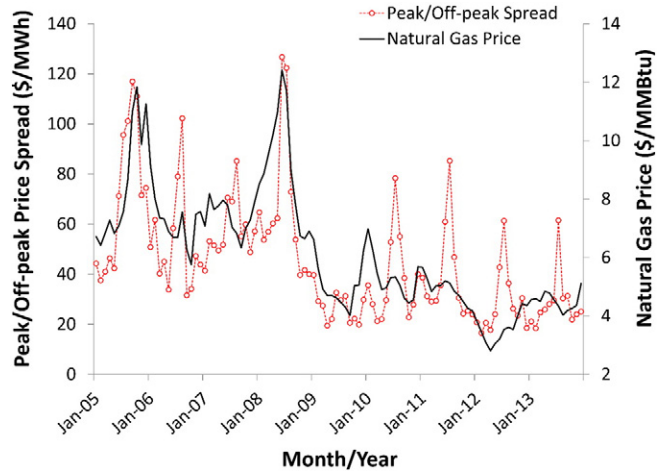

Fig. 2. Average monthly peak/off-peak electricity price spread in PJM Interconnection (black) and average delivered monthly natural gas prices for electric utilities over the years 2005–2013. The peak/off-peak price spread shows seasonality (increasing in summer and winter months) and a significant correlation with natural gas prices. Both average natural gas prices and peak/off-peak electricity show a step-change decrease in 2009 that persists through 2013.

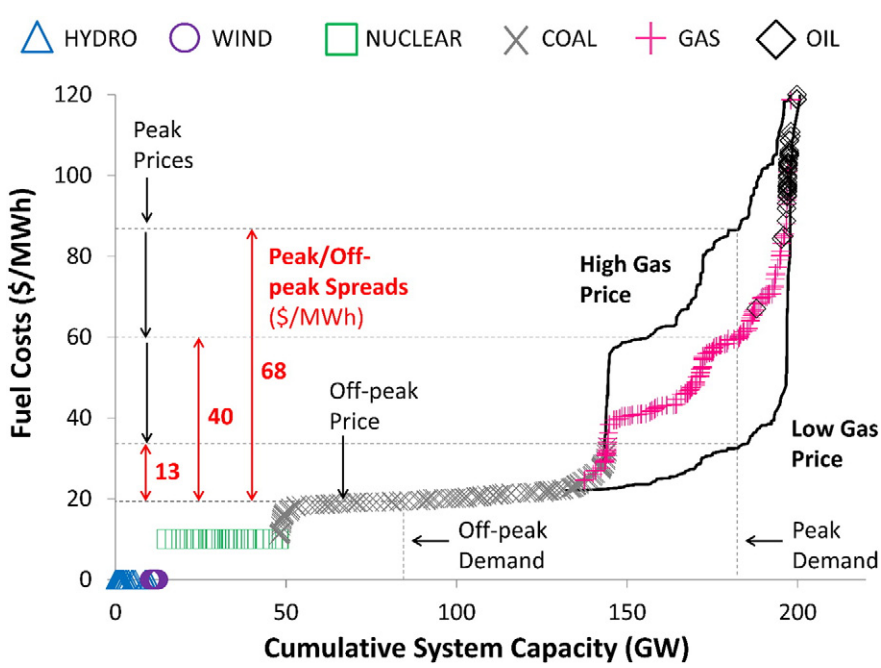

Fig. 1. Determination of peak/off-peak price spread in a wholesale electricity market. The peak/off-peak price spread increases and decreases with the price of natural gas. Market (peak and off-peak) prices are calculated as the intersection of vertical demand curves and the system supply (marginal cost) curve. The marginal cost curve was developed using EPA eGrid data for all generation resources within the PJM Interconnection footprint.

hydropower in the generation mix (Kataria, 2009; Aravena et al., 2012; Sundt and Rehdanz, 2015). A significantly lower cost of ramp rate restrictions could make it more feasible for utility customers to pay more for electricity on a volunteer basis in exchange for "low impact" hydro (utilities in most U.S. states already have programs that allow electricity customers to elect to pay a higher price for low carbon electricity) (DOE, 2015). Dam owners may also be able to recoup a greater share of the cost of ramp rate restrictions through the production of renewable energy credits (RECs), which, for hydroelectric dams, can be contingent on dams meeting a series of low impact criteria, including adherence to natural flow regimes (Low Impact Hydro Institute, 2015). Another possibility could be conservation oriented non-governmental organizations (NGOs) or citizen groups directly compensating dam owners for making operational changes at upstream dams in order to restore natural hourly flow patterns, a type of arrangement for which there is growing precedent (Freshwater Trust, 2014).

Nonetheless, even if the expected cost of ramp rate restrictions is significantly reduced on average, uncertainty in the peak/off-peak price spread, as well as in reservoir inflows, may cause large swings in the cost of these restrictions on a year-to-year basis. This variability, and the resulting financial uncertainty, could preclude dam owners and downstream stakeholders from engaging in these types of arrangements. Groups interested in improving flow regime may, therefore, find value in financial hedging strategies capable of significantly reducing year-to-year uncertainty in the cost of ramp rate restrictions. One such strategy could be the use of "collar" contracts between a downstream stakeholder and a third party insurer that compensate the stakeholder when the cost of ramp rate restrictions is high and require a pay-out to the insurer when costs are low, yielding net costs that approximate the long-term mean.

In what follows, we evaluate the extent to which recent low natural gas prices have reduced the cost of implementing ramp rate restrictions at a hydroelectric dam in PJM and develop a stochastic model for simulating the monthly cost of ramp rate restrictions based on the peak/off-peak price spread and reservoir inflows. This cost model is then used to price and implement a collar contract designed to help prospective downstream stakeholders who are interested in purchasing natural flow releases reduce their exposure to large year-to-year swings in the cost of ramp rate restrictions.

2. Methods

2.1. Study area and modeling framework

This paper focuses on the operation of Roanoke Rapids Dam, a 100 MW project in the Lower Roanoke River Basin (Virginia and North Carolina, U.S.) (see Fig. 3) that is owned and operated by Dominion Energy.

As the furthest downstream dam in the Roanoke River Basin, the operations of Roanoke Rapids Dam have been the subject of considerable scrutiny in the past, particularly with regard to impacts from peaking activities at the dam on downstream diadromous fish populations and extensive areas of un-fragmented bottomland hardwood forest (Pearsall et al., 2005; Whisnant et al., 2009; Dominion Energy, 2015).

We determine the monthly cost of ramp rate restrictions at Roanoke Rapids Dam over the period 2005–2013 by comparing simulated hydropower revenues at the dam under two different operational scenarios, which, respectively, represent the lowest and highest degree of hourly operational restrictions typically found at hydroelectric dams in the U.S.:

- *Unrestricted*: dam operators are free to schedule power production at Roanoke Rapids Dam in a manner that maximizes profits (with water releases up to a turbine capacity of 20,000 cubic feet per second), but reservoir discharges are subject to a modest FERC instantaneous minimum release requirement (325 cubic feet per second).
- *Restricted*: operations at Roanoke Rapids Dam are converted to "run-of-river", meaning outflows equal inflows on a daily basis and a static discharge is required in each hour of the day (i.e., peaking and other hourly changes in flow are prohibited)

Hydroelectric dams in the U.S. operate under a wide range of operational restrictions that impact their hour-to-hour flexibility in scheduling generation—these two scenarios are meant to represent two extremes at

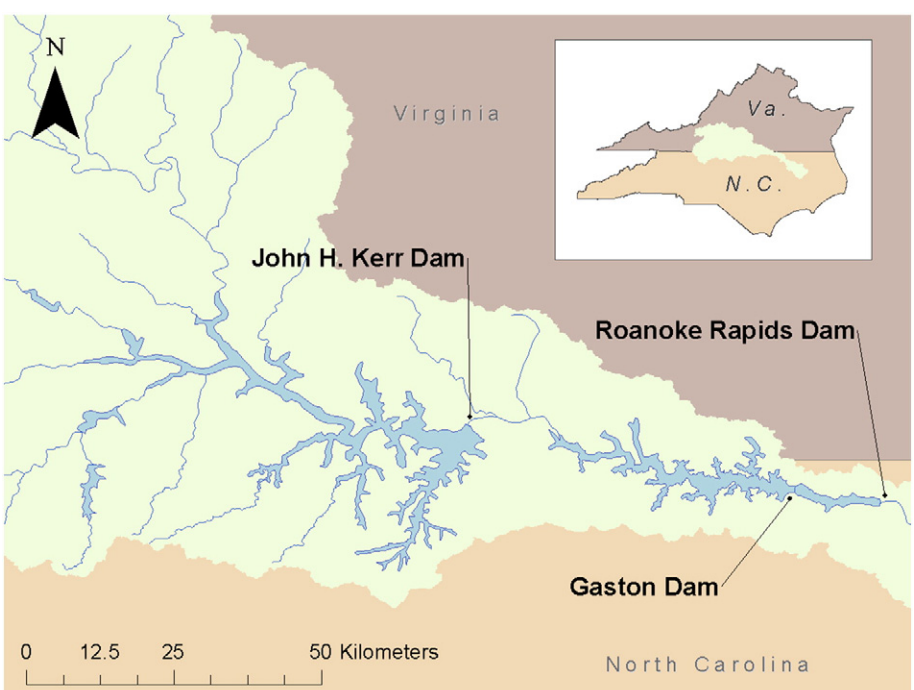

Fig. 3. Roanoke Rapids Dam (100 MW), the furthest downstream dam in the Roanoke River Basin (North Carolina and Virginia). Downstream of Roanoke Rapids Dam are highly valued bottomland hardwood forests managed by the Nature Conservancy.

either end of this spectrum. In reality, Roanoke Rapids Dam is operated according to both the "restricted" and "unrestricted" scenarios, depending on the time of year. During the spring spawning season for diadromous fish, the dam operates under the restricted scenario – during all other months, it is relatively free to maximize revenues via hydropeaking. However, in order to make the results of this study as transferable as possible, we choose to explore the difference between unrestricted and restricted scenarios and fully bound the potential effects of low gas prices on dams in the U.S. But, it is important to note that the marginal cost of imposing a fully restricted scenario would be less significant for any dams that already operate under some level ramp rate restrictions.

Differences in revenues calculated between the unrestricted and restricted scenarios thus represent the *maximum possible cost* of ramp rate restrictions at Roanoke Rapids Dam. Fig. 4 illustrates the typical electricity production schedules that result from both the unrestricted and restricted scenarios for a summer week in which roughly 2000MWh of total electricity can be produced, based on water availability. The unrestricted scenario produces a minimum amount of generation outside of peak hours (approximately 1.5 MW per hour, corresponding to the FERC minimum flow requirement), whereas the restricted scenario produces generation at rates dictated by average hourly reservoir inflows, which vary somewhat day-to-day.

The cost of restrictions at Roanoke Rapids Dam is calculated on a monthly basis as the difference in hydropower revenues between the unrestricted scenario and restricted scenario. Hydropower revenues at Roanoke Rapids Dam are maximized for both scenarios using a hydrologic-economic model of the basin and its three dams (see Fig. 3) adapted from previous work by the authors (Kern et al., 2011, 2014a, 2014b). The model (coded in Matlab) uses historical hydrological inputs of run-off, precipitation and evaporation, along with existing reservoir operating guidelines, to drive water balance equations and allocate daily volumes of water for release (hydropower production) at dams. Daily volumes of water available for hydropower production are then scheduled for release on an hourly basis using a deterministic, mixed integer optimization program coded in AMPL and solved using CPLEX. The optimization program maximizes profits from the sale of electricity over a rolling, 4-day planning horizon using historical day-ahead electricity prices from PJM, as follows:

$$Maximize\ Profits: \sum_{t=1}^{96}(Gen_t * Price_t) - (START_t * \text{Start Cost}) \tag{1}$$

where,

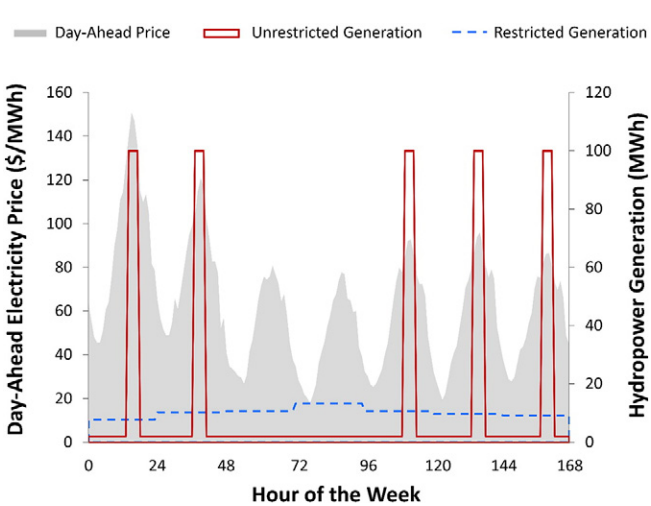

Fig. 4. Differences in hydropower generation schedules between the unrestricted (red) and restricted (blue, dashed) operational scenarios. The unrestricted scenario produces a minimum amount of generation outside of peak hours, whereas the restricted scenario produces generation a rates dictated by hourly reservoir inflows.

Gen_t electricity sold in in day ahead market in hour t (MWh)
$Price_t$ day ahead electricity price in hour t ($/MWh)
$START_t$ binary "on/off" variable indicating plant start
Start Cost cost associated with plant start

Compared to thermal generation, hydroelectric dams have significantly lower start costs – similar to Kern et al. (2014a), we assume $400/start. The maximization problem is subject to a number of operational constraints. For the unrestricted scenario, the following constraints apply:

$$\frac{Gen_t}{\delta} \le \text{Turbine Capacity}^{*}3600 * ON_t \qquad \forall t \tag{2}$$

$$\frac{Gen_t}{\delta} \ge \text{FERC Minimum Release}^{*}3600 * ON_t \qquad \forall t \tag{3}$$

$$\sum_{t=1}^{96}\frac{Gen_t}{\delta} \le \text{Available Reservoir Storage} \tag{4}$$

$$START_t \ge ON_t - ON_{t-1} \qquad t \in \{2\ldots96\} \tag{5}$$

where,

δ Efficiency of turbine $\left(\frac{\text{MWh}}{\text{cubicfeet}}\right)$
Turbine Capacity 20,000 cubic feet per second
Available Storage cumulative 4 day storage available for release determined by hydrologic model (cubic feet)
ON_t binary on/off variable indicating production of electricity
FERC Minimum Release 325 cubic feet per second

The amount of generation scheduled in any given hour is bounded by the maximum turbine capacity of the dam (Eq. (2)) as well as minimum instantaneous release requirements stipulated in the dam's FERC license (Eq. (3)). The total amount of generation scheduled over any 4-day period (Eq. (4)) is also bounded by the availability of reservoir storage, as determined by the hydrological model.

Normally, $\boldsymbol{\delta}$ (turbine efficiency) is a dynamic value, one that depends on the hydraulic head of the dam (vertical difference between reservoir and tailrace elevation); however, Roanoke Rapids Dam has significant lake level constraints that effectively prohibit it from storing water released by upstream dams; as a result, hydraulic head at the dam (and thus also turbine efficiency) can be considered a constant.

For the restricted scenario, a single constraint is included. In order to force reservoir releases to mimic natural hourly variability in river flows (which is fairly small except during significant precipitation events), we include a stipulation for static hourly flows within each 24-h period:

$$\frac{Gen_{d*t}}{\delta} = \min\left(\text{Turbine Capacity} * 3600, \frac{\text{Inflows}_d}{24}\right) \quad d\in\{1\ldots4\}, t\in\{t\ldots24\} \tag{6}$$

where

Inflows_d reservoir inflows in day d (cubic feet)

It is important to note that since the dam is operated as run-of-river (inflows equal outflows) on a 4-day rolling basis, and since we assume a static turbine efficiency (hydraulic head), there is no difference in total generation between the two scenarios. They only differ in how that generation is scheduled on an hourly basis.

The perspective presented by this paper is one of a profit-maximizing firm selling all of its electricity into a wholesale day-ahead electricity market. We do not consider how ramp rate restrictions at dams may impact the larger system costs of a vertically integrated utility whose main objective is to minimize the cost of meeting electricity demand and adhering to reliability constraints. We also do not consider revenue generating opportunities outside the sale of electricity (e.g., provision of ancillary services like

frequency regulation or spinning reserves). In terms of future research, these may be important considerations in providing a more nuanced estimate of the cost of ramp rate restrictions at dams, but we do not expect them to weaken any results found from this analysis.

2.2. Hedging the cost of ramp rate restrictions

If low natural gas prices have significantly decreased the cost of ramp rate restrictions at hydroelectric dams in the PJM market, it could expand conservation opportunities beyond current, commonly used approaches (namely FERC relicensing and litigation) to include a third option: downstream stakeholders "purchasing" more environmentally friendly practices from dam owners on a volunteer basis. In the case of Roanoke Rapids Dam, this would entail stakeholders directly compensating dam owners for losses incurred from the implementation of ramp rate restrictions. There is growing precedent for this type of arrangement, both in the electric power sector to promote the use of renewable energy (DOE, 2015; Low Impact Hydropower Institute, 2015) and as a tool used by NGOs to promote conservation of river ecosystems (Freshwater Trust, 2014). Even with a lower cost of restrictions, however, uncertainty in the peak/off-peak price spread, as well as in reservoir inflows, may undermine the viability of these types of agreements. If implementation of restrictions is agreed upon *ex ante* and payments from the stakeholder to the dam owner are made *ex post*, then unexpectedly high costs of restrictions are a potential risk. Both the dam owner and downstream stakeholder may require some part of this risk to be transferred to a third party in order to reduce the chances of a shortfall on the part of the stakeholder, and to allow the stakeholder more budget certainty.

With this in mind, we explore the potential for financial hedging strategies to reduce uncertainty for downstream stakeholders interested in "purchasing" ramp rate restrictions at dams (i.e., sending "make-whole" payments to the dam owner immediately following a month in which restrictions are implemented). An extensive body of literature exists on hedging strategies related to hydropower production, but to date these efforts have focused exclusively on the use of derivatives and insurance to reduce dam owners' exposure to low revenues (Mo et al., 2001; Fleten et al., 2010; Sanda et al., 2013; Kern et al., 2015; Foster et al., 2015). In this paper, we develop an approach that would allow a downstream stakeholder to lock-in a nearly constant year-to-year cost of restrictions by engaging a third party insurer in a financial "collar" contract (Hull, 2005). In a collar contract between a downstream stakeholder and third party insurer, both parties agree to a financial exchange determined by the cost of ramp rate restrictions, as follows:

$$Collar_T = \max(C_T - E[C_T], 0) - \max(E[C_T] - C_T, 0) \tag{7}$$

where,

C_T	cost of restrictions in month T, calculated *ex post*
$E[C_T]$	expected cost of restrictions in month T, calculated *ex ante*

When $\boldsymbol{C_T} > E[\boldsymbol{C_T}]$ the value of $\boldsymbol{Collar_T}$ is positive and a payment of that amount is made from the insurer to the downstream stakeholder. Alternatively, when $\boldsymbol{C_T} < E[\boldsymbol{C_T}]$, the value of $\boldsymbol{Collar_T}$ is negative and a payment of that absolute amount is made from the downstream stakeholder to the insurer (if $\boldsymbol{C_T} = \boldsymbol{E}[\boldsymbol{C_T}]$ no exchange of funds occurs). Thus, in high cost periods (i.e., whenever $\boldsymbol{C_T} > E[\boldsymbol{C_T}]$) the collar agreement is a source of funds for the downstream stakeholder that can be used to defray any portion of the "make whole" payments to the dam owner in excess of $\boldsymbol{E}[\boldsymbol{C_T}]$. In low cost periods, however, (i.e., whenever $\boldsymbol{C_T} < \boldsymbol{E}[\boldsymbol{C_T}]$) the downstream stakeholder must make a payment to the insurer equal to $(\boldsymbol{E}[\boldsymbol{C_T}] - \boldsymbol{C_T})$.

In order to participate in the collar contract, the downstream stakeholder is required to pay a premium ($\boldsymbol{P_T}$) to the insurer to cover the insurer's cost of capital and return on investment, and account for underlying parameter uncertainty. Net costs incurred by the downstream stakeholder in each period are thus a function of three components: 1) the cost of restrictions in month $\boldsymbol{T}$ ($\boldsymbol{C_T}$) (paid to the dam owner); 2) the premium associated with the collar contract ($\boldsymbol{P_T}$) (paid to the insurer); and 3) the collar payoff function (Eq. (7)) (exchanged with the insurer), as follows:

$$Net\ Cost_T = C_T + P_T - Collar_T \tag{8}$$

This type of arrangement guarantees that the downstream stakeholder always makes a constant net payment of $(\boldsymbol{E}[\boldsymbol{C_T}] + \boldsymbol{P_T})$.

Fig. 5 shows how collar contracts between the stakeholder and third party insurer are incorporated alongside an agreement between the stakeholder and dam owner for implementation of ramp rate restrictions. We assume that agreements between the stakeholder and the dam owner are made 1 year prior to the "coverage period", i.e., the month $\boldsymbol{T}$ in which restrictions will be implemented. Premiums ($\boldsymbol{P_T}$) that must be paid by the stakeholder in order to engage in a collar contract are likewise determined one year prior to the coverage period.

2.2.1. Premium calculations

For novel and untested contracts, such as the one proposed here, modeling contract premiums can be difficult (Tsanakas and Desli, 2005). Risk preferences of the market actors are unknown — i.e., we are not able to know with certainty what value a stakeholder would place on being able to reduce year-to-year variability in the cost of restrictions. In addition, typical approaches for pricing financial instruments, such as the use of replicating portfolios and the "no arbitrage" principal, don't apply (Richards et al., 2004). The cost of ramp rate restrictions is driven in part by reservoir inflows, a non-traded environmental variable—so we cannot replicate the performance of a collar contract by buying or selling any combination of other securities. In general, this is a challenge that extends to the pricing of all "weather derivatives", i.e., instruments that pay-out based on the value of meteorological variables such as wind speed or temperature. As a result, weather derivatives are often priced using actuarial (as opposed to financial) methods that determine contract prices based on the statistical moments of the underlying weather variable (Richards et al., 2004; Young, 2004). In this paper, we use an approach that merges financial and actuarial principles to price contracts with non-normal probability distributions (Wang, 2000, 2002). The approach, known as the Wang transform, works by distorting an empirical probability distribution of a pay-out function (in our case, the $Collar_t$ formula shown in Eq. (7)) such that the probability of pay-outs from the insurer are weighted more heavily, thus achieving a "risk neutral" distribution. We develop empirical probability distributions via "burn analysis" (high volume stochastic simulation), an approach commonly used in the pricing of weather derivatives (Jewson and Brix, 2005).

Premiums are calculated as follows: for a given coverage period $\boldsymbol{T}$ we simulate 1000 possible values of $\boldsymbol{C_T}$ using a stochastic model fitted to historical data (see Section 2.2.2 for description of the stochastic model). This sample is then used to empirically derive a cumulative distribution function for $\boldsymbol{Collar_T}$. The cumulative distribution function of $\boldsymbol{Collar_T}$ is then transformed as shown in Eq. (9) in order to account for the third party insurer's cost of capital and return on investment, and underlying parameter uncertainty. This transform assigns more weight to the probability of positive collar payouts (instances when the insurer is paying the downstream stakeholder).

$$F^*(Collar_T) = \mathrm{Q}\left[\varphi^{-1}(F(Collar_T)) + \lambda\right] \tag{9}$$

where,

$F^*(Collar_T)$	risk adjusted cumulative dist. function (cdf) of $Collar_T$
Q	student T test with n degrees of freedom (n = sample size)
φ	standard normal cumulative distribution function
$F(Collar_T)$	original cdf of $Collar_T$
λ	market price of risk

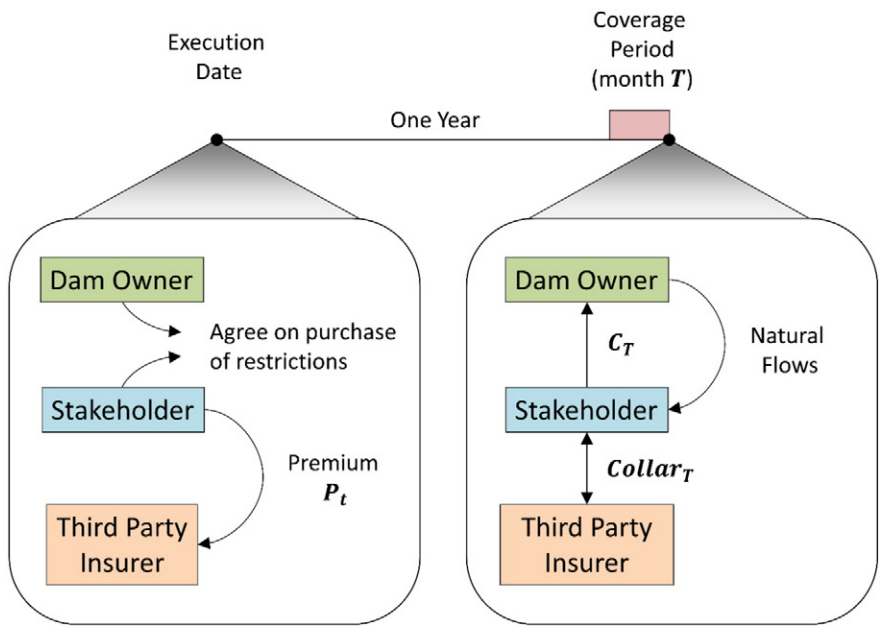

Fig. 5. Incorporation of collar contracts between the stakeholder and third party insurer alongside an agreement between the stakeholder and dam owner for implementation of ramp rate restrictions. We assume that agreements between the stakeholder and the dam owner are made 1 year prior to the "coverage period", or the month $\boldsymbol{T}$ in which restrictions will be implemented. Premiums ($\boldsymbol{P_T}$) are likewise calculated 1 year prior. Immediately following the coverage period, the stakeholder pays the dam owner the *ex ante* cost of restrictions. At the same time, the collar contract payouts are distributed.

A monthly premium ($\boldsymbol{P_T}$) is then calculated as the expected value of $\boldsymbol{Collar_T}$ *after* its distribution function has been risk adjusted.

Premiums calculated in this manner are said to equal the expected value of $\boldsymbol{Collar_T}$ *before* its distribution has been transformed (by definition, \$0) plus an additional "loading" determined by the value of $\boldsymbol{\lambda}$, also known as the "market price of risk." The Wang Transform thus requires an assumption regarding what risk is trading for in the market, (i.e. what returns are for products with similar risk profiles). It also makes an assumption of market completeness and does not account for transaction costs (Tsanakas and Desli, 2005). These assumptions are reasonable given the scope of this work, but they are important to keep in mind when interpreting contract premiums described in the results section. Similar to previous studies that have employed the Wang transform to price index-based insurance products and weather derivatives, here $\boldsymbol{\lambda}$ is assumed to equal 0.25, but it is anticipated that this number would vary based on market conditions and user preferences (Wang, 2002; Kern et al., 2015; Foster et al., 2015).

2.2.2. Stochastic cost model

Due to the limited length of the historical record of electricity prices in the PJM market, historical $\boldsymbol{C_T}$ is only available for the years 2005-present. This amount of data is insufficient to form robust estimates of premiums ($\boldsymbol{P_T}$) and test the performance of collar contracts. In order to circumvent this data limitation, we make use of a stochastic model of the monthly cost of restrictions at Roanoke Rapids Dam. The stochastic cost model is used to create very large synthetic samples of $\boldsymbol{C_T}$ for any given month, taking into account uncertainty in reservoir inflows and the peak/off-peak price spread. These synthetic samples are then used in calculating contract premiums via "burn analysis" and in testing contract performance.

The linear structure of the stochastic cost model was identified by fitting a wide range of possible model structures to historical $\boldsymbol{C_T}$ data using stepwise linear regression. The best fitting model ($R^2 = 0.87$) was found to be a quadratic that represents the monthly cost of ramp rate restrictions as a function of the peak/off-peak price spread and reservoir inflows. An explanation for this structure (in particular, the non-linear relationship between the cost of restrictions and reservoir inflows) can be found in Section 3.2 of the results.

$$C_T = \left(a + b * F_T + c * F_T{}^2\right) * d * S_T + \epsilon_T \tag{10}$$

where

C_T	cost of restrictions in month T (\$M)
$\{a,b,c,d\}$	empirically derived coefficients
F_T	inflows at Roanoke Rapids Dam in month T(kilo cubic feet per second)
S_T	average peak/off peak price spread in month T ($\frac{\$}{\mathrm{MWh}}$)
ϵ_T	zero mean Gaussian error process

Values for the parameters $\boldsymbol{a}$, $\boldsymbol{b}$, $\boldsymbol{c}$ and $\boldsymbol{d}$ in Eq. (10) are optimized to maximize linear correlation (R^2) and minimize the sum of squared errors when comparing modeled and historical costs. The peak/off peak price spread $\boldsymbol{S_T}$ is assumed to reflect the difference between the highest and lowest hourly price in each day, averaged over an entire month.

In order to create large synthetic samples of $\boldsymbol{C_T}$ from the stochastic model described in Eq. (10), inputs of inflows ($\boldsymbol{F_T}$) and the peak/off-peak price spread ($\boldsymbol{S_T}$) must also be generated. We model the peak/off-peak price spread in each month as a quadratic function with interactions among electricity demand, natural gas prices and reservoir inflows (a proxy for the system wide availability of hydropower). This model shows a strong fit ($R^2 = 0.87$) with historical price spread data in PJM, will all predictor variables showing statistical significance (p-value ≤ 0.05).

$$S_T = e + f * D_T + g * F_T + h * G_T F_T + i * D_T{}^2 + j * G_T{}^2 + \epsilon_T \tag{11}$$

where

S_T	peak/off peak price spread in month T ($\frac{\$}{\mathrm{MWh}}$)
E	empirical coefficients for month T
D_T	electricity demand in month T(MWh)

F_T inflows at Roanoke Rapids Dam in month T(kilo cubic feet per second)
G_T natural gas price in month T ($\frac{\$}{\text{MMBtu}}$)
ϵ_T zero mean Gaussian error process

With the two models described above (Eqs. (10) and (11)), an infinitely long synthetic time series of $\boldsymbol{C_T}$ can be simulated for any month of interest via Monte Carlo simulation of $\boldsymbol{D_T}$, $\boldsymbol{F_T}$,and $\boldsymbol{G_T}$ (the three underlying processes that drive the peak/off-peak price spread and the cost of restrictions). However, an important consideration when sampling these predictors is maintaining any existing autocorrelation and/or covariance structures among them.

In the case of electricity demand ($\boldsymbol{D_T}$) and reservoir inflows ($\boldsymbol{F_T}$), no significant levels of year-to-year autocorrelation exist in the study area. However, natural gas prices ($\boldsymbol{G_T}$) do exhibit statistically significant levels of autocorrelation at a 12-month lag. Since large fluctuations in the price of natural gas can persist for more than one year, we model natural gas prices using an Orenstein–Uhlenbeck (OU) stochastic difference model fit to historical prices. In order to maintain covariance structures among $\boldsymbol{D_T}$, $\boldsymbol{F_T}$ and $\boldsymbol{G_T}$, for each year of gas prices simulated by the OU process, all three predictor variables are sampled with replacement from their joint probability distribution. Sampling is performed until a triplet is found that contains a value of $\boldsymbol{G_T}$ approximately equal to the value simulated by the OU process. This process is repeated for each simulation year, until a sufficient number of synthetic values of $\boldsymbol{D_T}$, $\boldsymbol{F_T}$ and $\boldsymbol{G_T}$ is achieved. These values are then used to calculate corresponding values of $\boldsymbol{S_T}$ and $\boldsymbol{C_T}$ and $\boldsymbol{E}[\boldsymbol{C_T}]$.

3. Results and discussion

3.1. Low natural gas prices and the cost of restrictions

Fig. 6 shows the historical cost of ramp rate restrictions at Roanoke Rapids Dam over the period 2005–2013. In Fig. 6(a), the linear trend shows a 50% reduction in the cost of restrictions over this time period, decreasing from approximately \$0.5 M/month in early 2005 to around \$0.25 M/month at the end of 2013. A visible discontinuity (decrease in the mean and volatility of the cost of restrictions) occurs in late 2008/early 2009 and is shown to persist throughout the remainder of the time series. This step-change coincides with: 1) a global financial crisis that significantly reduced economic productivity; and 2) a prolonged reduction in natural gas prices made possible by increased supply from horizontal hydraulic fracturing.

It is important to note, however, that this overall decrease in the cost of ramp rate restrictions does not occur uniformly across all months. We find that summer and winter months generally show sharp decreases in the cost of restrictions (Fig. 6(b)), because utilities typically rely much more on natural gas generation in these months to meet higher demands for cooling/heating. On the other hand, low demand months in spring experience very little change in the cost of restrictions (Fig. 6(c)), because utilities are not as exposed to natural gas prices in these months. This is of particular note in the Roanoke River Basin, where much of the concern over hydropower peaking surrounds its impacts on diadromous fish spawning from March to June. These results suggest that, at least in the Roanoke River Basin, the financial cost of reducing the specific impacts of hydropower peaking on spring fish spawning *has not* decreased significantly from 2005 to 2013.

A primary goal of this study is to determine the extent to which low natural gas prices have been responsible for decreases in the cost of ramp rate restrictions at Roanoke Rapids Dam. Linear correlations were calculated among several factors that contribute to the peak/off-peak price spread and the cost of restrictions, including long-term (2005–2013) average monthly electricity demand and demand anomalies (i.e., departures from average monthly demand due to extreme weather and/or economic conditions) (Table 1). These factors were found to influence the peak/off-peak price spread and the cost of ramp rate restrictions; however, fluctuations in the price of natural gas are the single most important driver.

Natural gas prices are the primary influence on peak prices ($R^2 = 0.67$); in turn, peak prices are the main driver of the peak/off-peak spread ($R^2 = 0.94$), which directly impacts the cost of restrictions ($R^2 = 0.76$). Overall, natural gas prices explain around 40% of observed variation in the monthly cost of restrictions. This strongly suggests that

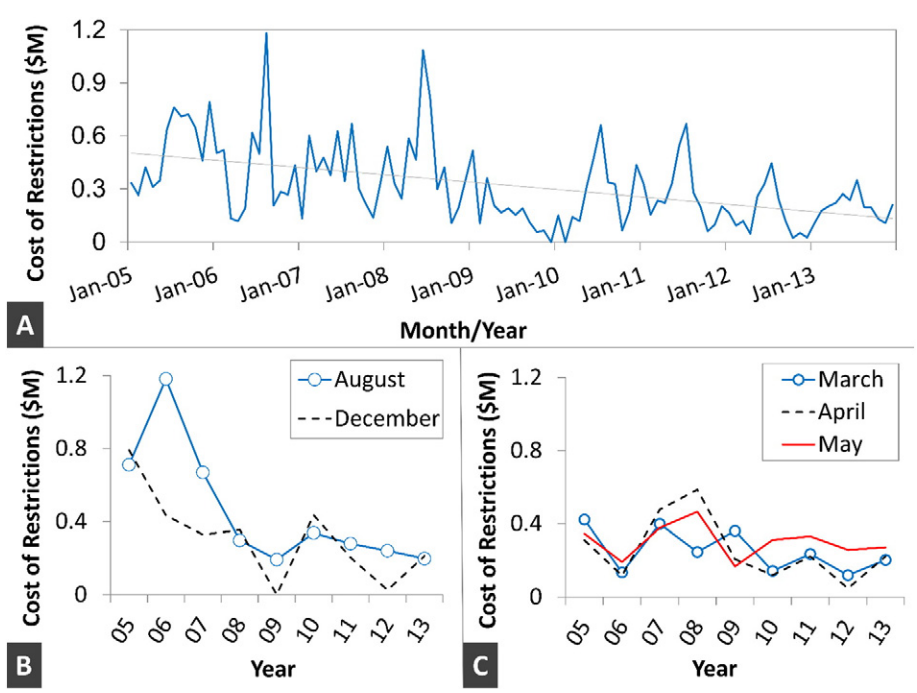

Fig. 6. (a): The monthly cost of ramp rate restrictions at Roanoke Rapids Dam from 2005 to 2013. (b): The cost of restrictions declined the most over this period for high demand months like August and December. (c): For spring months in which the ecological impacts of hydropower peaking in Roanoke Rapids Dam are particularly concerning, there has not been a significant decrease in costs.

Table 1
R^2 values among power system (demand, demand anomalies) and fuel market (natural gas prices) variables, price dynamics (peak electricity prices, peak/off-peak spread) and the cost of ramp restrictions for the months January 2005–December 2013. Delivered gas prices strongly influence peak prices ($R^2 = 0.67$); in turn, peak prices are the main driver of the peak/off-peak spread ($R^2 = 0.936$), which impacts the cost of restrictions ($R^2 = 0.76$). Overall, natural gas prices explain around 40% of the observed variation in the monthly cost of restrictions at Roanoke Rapids Dam.

	Average demand	Demand anomalies	Natural gas prices	Peak price	Spread
Demand anomalies	0.001				
Natural gas prices	0.003	0.149			
Peak price	0.142	0.377	0.671		
Spread	0.131	0.323	0.572	0.936	
Cost of restrictions	0.133	0.311	0.404	0.740	0.758

lower natural gas prices, driven in large part by increased supply from fracking, have caused a significant reduction in the cost of implementing ramp rate restrictions at dams.

3.2. Validation of the stochastic cost model

Fig. 7(a) maps the monthly cost of restrictions at Roanoke Rapids Dam over the period 2005–2013 according to peak/off-peak price spread (x-axis) and inflows (y-axis). This historical cost data was used to calibrate the stochastic model (see Eq. (10)) that estimates the seasonal cost of restrictions at Roanoke Rapids Dam based on reservoir inflows and the peak/off-peak price spread. Fig. 7(b) shows a representation of the calibrated model.

The cost of restrictions is shown to be linearly dependent on the peak/off-peak price spread, while, for any given price spread, the cost of restrictions changes as a function of inflows in a non-linear manner. The lowest costs occur at very high and very low inflow levels (under both of these conditions, ramp rate restrictions force dam operators to shift minimal amounts of generation from peak to off-peak hours). The highest cost values occur at intermediate flows levels, when ramp rate restrictions force dam owners to shift the greatest amount of generation from peak to off-peak hours.

The non-linear relationship between inflows and the cost of restrictions can also be understood in terms of changes in the marginal value of hydropower (Fig. 7(c)). The cost of restrictions increases as monthly reservoir discharge (hydropower production) increases above the FERC minimum release, because the marginal value of hydropower production for the unrestricted scenario (MV_U) is higher than the marginal value of hydropower in the restricted scenario (MV_R). This condition holds for all of the area labeled as "Condition 1" in Fig. 7(c). However, the difference between MV_U and MV_R narrows as a function of reservoir discharge, and eventually becomes zero. This occurs at the inflection (maximum cost) point. At monthly reservoir discharges higher than this, MV_R is actually higher than MV_U (in the restricted scenario, the dam continues to produce electricity in a combination of high and low value hours, while the unrestricted scenario has only low value hours remaining in which to produce electricity). As a result, the cost of restrictions begins to decline. This condition holds for all of the area labeled as "Condition 2" in Fig. 7(c). The cost of restrictions drops to zero when reservoir inflows are high enough to force the dam owner to produce electricity at turbine capacity in every hour of the month.

Fig. 7(d) confirms that a stochastic cost model based on a combination of inflows and the peak/off-peak price spread has a high capacity for reproducing observed data, with $R^2 = 0.87$ and MSE of \$55,000/month). Validation metrics are also improved substantially by calibrating models separately by month or season.

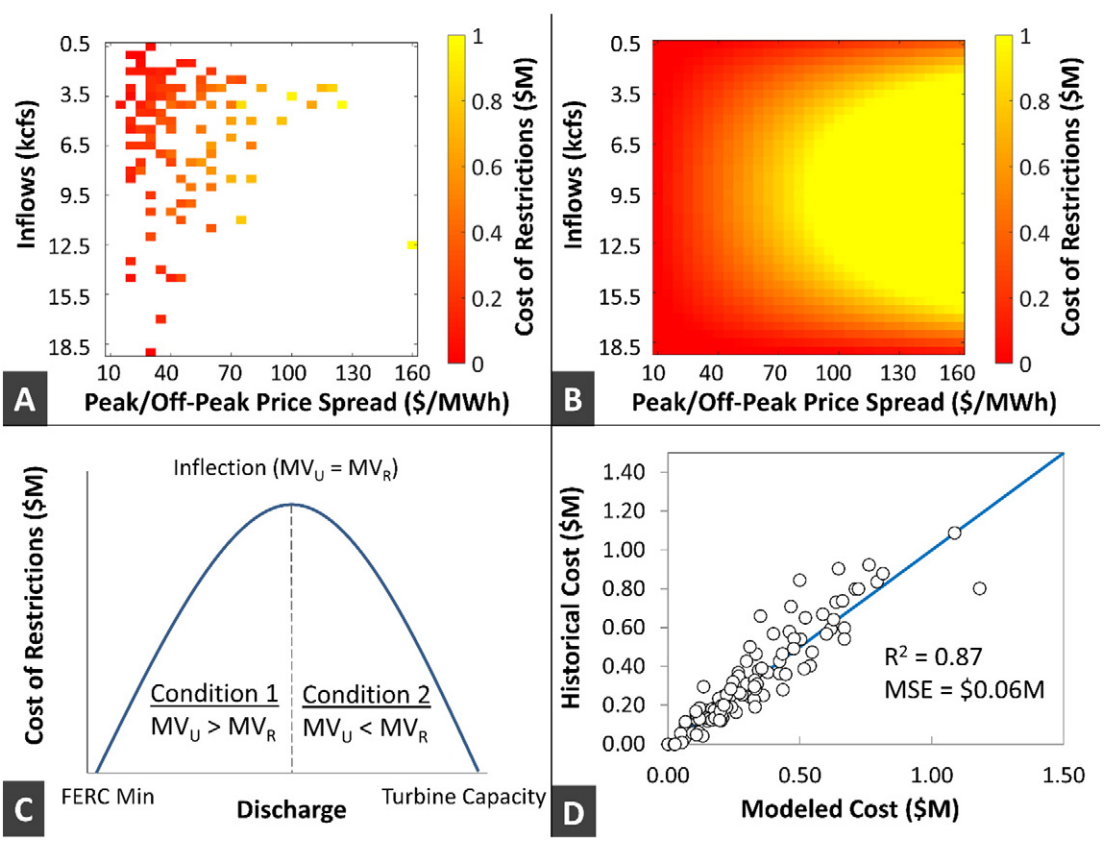

Fig. 7. (a): 2005–2013 monthly cost of restrictions mapped by reservoir inflows (kcfs) and peak/off-peak price spread. (b): Calibrated model of the cost of ramp rate restrictions (see Eq. (10)). (c): Relationship between daily reservoir discharge and the cost of restrictions. The cost of restrictions increases while the marginal value of hydropower production is greater for the unrestricted scenario (Condition 1) and decreases after the marginal value of hydropower production becomes higher for the restricted scenario (Condition 2). (d): Validation of cost model. Results show uncertainty in the cost of ramp rate restrictions is due almost entirely to reservoir inflows and the peak/off-peak price spread.

Uncertainty in inflows and the peak/off-peak price spread vary widely by calendar month. As a result, different months have historically demonstrated different levels of uncertainty in the cost of ramp rate restrictions (Table 2). In general, months with relatively low electricity demand and little uncertainty in reservoir inflows – in the Southeastern U.S., the months of September and October – exhibit little variation in the cost of restrictions. High demand summer and winter months, however, show much greater levels of uncertainty. This is due partly to greater variability in reservoir inflows and greater exposure to changes in fuel prices, but also to the shape of the PJM's electricity supply curve (see Fig. 1). When system-wide electricity demand is high, peak electricity prices, as well as the peak/off-peak price spread, are much more sensitive to changes in marginal increases in demand (i.e., small rightward shifts in the vertical demand curve caused by a hotter summer/colder winter can cause non-linear increases in price).

3.3. Collar contract performance

Results from this analysis demonstrate that low natural gas prices have significantly reduced the cost of implementing ramp rate restrictions at hydroelectric dams in the PJM market. If low natural gas prices are sustained over several years, it could expand conservation opportunities by making it more affordable for downstream stakeholders to "purchase" ramp rate restrictions at dams. Nonetheless, year-to-year uncertainty in the peak/off-peak price spread, as well as in reservoir inflows, may undermine the viability of these types of arrangements. A case in point is the "polar vortex" of early 2014 that caused record low temperatures throughout much of the eastern U.S. After years of falling natural gas prices and a declining peak/off-price electricity price spread, record low temperatures caused delivered natural gas prices for electric utilities to increase from $5.11/MMBtu to $7.47/MMBtu (see Appendix 1). Low temperatures increased demand for electricity and simultaneously caused several power plants in the PJM footprint to experience unforced outages (PJM, 2014). As a result, peak electricity prices at one point eclipsed $1000/MWh and the average peak/off-peak price spread for January 2014 reached a historic high of $160/MWh. The financial penalty associated with ramp rate restrictions at Roanoke Rapids Dam, had they been in place, would have been more than $2.5 million for the month of January alone (for reference, the average cost of restrictions in January over 2005–2013 would have been $338,000 with a standard deviation of $178,000).

Although an extreme example, the 2014 polar vortex is emblematic of how uncertainty in the year-to-year cost of restrictions could undermine potential arrangements between downstream stakeholders and dam owners for the purchase of ramp rate restrictions. With this in mind, we explore the effectiveness of a collar contract (see Eq. (7)) between a downstream stakeholder and third party insurer at reducing uncertainty in the cost of ramp rate restrictions. Results are shown for a collar contract developed specifically for the month of June, a month with ecological importance in the Roanoke River, and one that has historically demonstrated high levels of year-to-year variability in the cost of restrictions (see Table 2). The contract was tested using a 1000-year synthetic sample of the June cost of restrictions generated using the calibrated stochastic cost model (see Eq. (10)). In designing and testing this contract, natural gas prices were assumed to be similar to those from 2009-present, i.e., lower and less volatile.

Fig. 8 shows probability distribution functions of the cost of restrictions in June for the downstream stakeholder without a collar agreement in place ($\boldsymbol{C_T}$) ($\mu = \$297{,}000$; $\sigma = \$126{,}000$) and the net cost of restrictions with the collar agreement (Eq. (8)) ($\mu = \$340{,}000$; $\sigma = \$9300$). Even under lower and less volatile natural gas prices, there is considerable uncertainty in the June cost of restrictions ($\boldsymbol{C_T}$) caused by a combination of year-to-year fluctuations in inflows, natural gas prices and electricity demand. With the collar agreement in place, this uncertainty is all but eliminated. Some remains because natural gas prices are significantly autocorrelated at a lag of 12 months, and, as a result, changes in the price of natural gas cause E[$\boldsymbol{C_T}$] and thus the contract premium ($\boldsymbol{P_T}$) to fluctuate. The average premium required by the third party insurer to engage in the collar agreement for June is $40,000, though premiums range from $38,000 and $46,000 (they increase/decrease each year with the price of natural gas).

Note that the expected net cost of restrictions with the collar in place is $43,000 higher than the expected cost of restrictions without the collar (about 15% of $\boldsymbol{E}[\boldsymbol{C_T}]$); this increase, roughly equivalent to the premium, is the effective price the stakeholder pays for cost certainty. The collar agreement enables the downstream stakeholder to lower its net costs when $\boldsymbol{C_T}$ is high (collar payments are used to defray costs above $\boldsymbol{E}[\boldsymbol{C_T}]$); but it increases net costs for the downstream stakeholder to a slightly greater extent when $\boldsymbol{C_T}$ is low. This is the tradeoff that the stakeholder must make to eliminate the risk of large swings in the year-to-year cost of ramp rate restrictions—slightly higher costs on average in exchange for financial certainty.

4. Conclusions

Findings from this study confirm that, on average, the average cost of ramp rate restrictions significantly decreased over the period 2005–2013, and that this decrease is strongly associated with a narrower peak/

Table 2
Average monthly peak/off-peak price spread, reservoir inflows, and cost of ramp rate restrictions at Roanoke Rapids Dam for the period 2005–2013. High demand summer months have the highest (but also most uncertain) price spread and cost of restrictions. Hydrological uncertainty is highest in winter and lowest in fall. Spring and fall months show the lowest cost of restrictions, due primarily to lower price spreads.

	Peak/off-peak spread ($/MWh)		Inflows (kcfs)		Cost of Restrictions ($)	
	Avg.	*Std. Dev.*	*Avg.*	*Std. Dev.*	*Avg.*	*Std. Dev.*
January	39.66	13.67	8.38	4.86	308,435	177,375
February	36.32	16.17	6.83	5.05	249,637	201,319
March	34.76	13.28	7	3.74	251,401	116,609
April	35.09	15.41	6.61	2.69	256,639	175,685
May	36.64	13.33	6.31	2.27	302,307	92,723
June	60.65	28.96	6.49	3.3	527,290	269,638
July	75.79	25.64	4.71	2.95	521,883	219,979
August	62.38	28.92	3.13	0.43	456,123	333,270
September	44.96	29.42	3.08	0.94	288,735	190,594
October	39.95	29.44	2.73	1.86	176,723	194,745
November	37.42	16.52	5.19	5.4	173,302	126,801
December	39.2	17.79	7.49	5.28	309,463	240,760

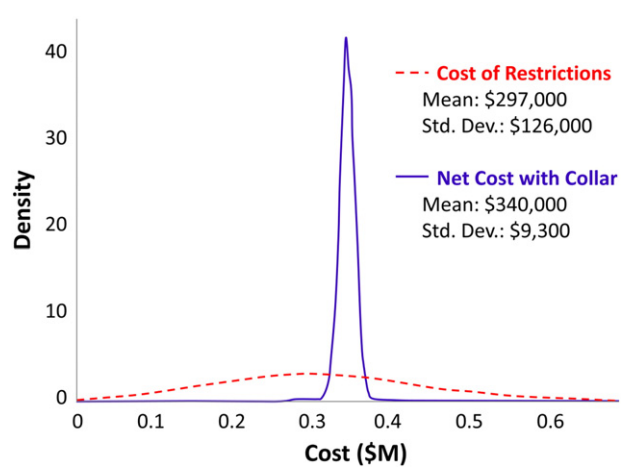

Fig. 8. Comparison of empirically derived probability density functions for the cost of ramp rate restrictions (red) and the net cost of restrictions with a collar agreement in place (blue) for the month of June. Even under more recent, relatively low natural gas price volatility, a wide distribution of costs is possible in this month. The collar agreement all but eliminates this uncertainty, for an average premium of $40,000.

off-peak price spread caused by lower natural gas prices. It is important to note, however, that the most significant reductions in the cost of restrictions were found in high demand winter and summer months. In regions where the ecological importance of ramp rate restrictions at dams is tied to other periods of the year (e.g., fish spawning in spring months), the cost of reducing impacts on river ecosystems has likely declined to a lesser extent. It is also important to note that the persistence of current low natural gas prices into the future is uncertain. In general, natural gas prices are expected to increase gradually over the next several decades due to increasing demand (Logan et al., 2013; EIA, 2015a), and recent events like the polar vortex of 2014 suggest that increasing demand may make prices more volatile, if not higher on average. Nonetheless, if low prices do persist, it could open valuable opportunities for improving environmental flows at hydroelectric dams.

Although natural gas prices have in recent years neared a 20-year low point, even relatively low levels of volatility in gas prices, combined with uncertainty in electricity demand and reservoir inflows, can cause large year-to-year fluctuations in the cost of ramp rate restrictions. With this in mind, we evaluated the use of third party collar contracts to help a hypothetical downstream stakeholder reduce year-to-year financial uncertainty associated with the purchase of more environmentally friendly flow patterns from an upstream dam owner. Results suggest that for a relatively small premium, the downstream stakeholder can dramatically reduce fluctuations in costs and eliminate the risk of unexpectedly large payments. Although this type of hedging strategy increases the average cost of restrictions for the downstream stakeholder, the associated increase in financial certainty may be critical in facilitating such an agreement. The potential of collar contracts in reducing financial uncertainty for purchasers of ramp rate restrictions, within a larger economic context of sustained low natural gas prices, may provide the basis of another viable pathway (outside of litigation and the FERC relicensing) for the restoration of hourly variability in river flows. We also suggest that the use of collar contracts to facilitate cooperation between up- and downstream dam owners and water users need not be limited to the implementation of environmental flow provisions. These contracts could apply equally to an agreement between any two water users whose objectives involve conflict over the magnitude and timing of water availability (e.g., agricultural producers and conservation proponents, agricultural producers and hydropower producers, etc.).

In a larger sense, this study demonstrates the ability for larger market driven and technological changes in the electric power industry to alter the marginal value of hydropower in power systems. It also highlights the need for significantly more research that investigates how ongoing changes in this sector (in particular, a shift away from coal to natural gas, renewables, battery storage, and dynamic demand side management) will impact the value of flexible hydropower capacity, not only in providing electricity, but also ancillary services. Deeper knowledge in this area is critical to understanding the financial obstacles to implementing more environmentally friendly practices at hydroelectric dams in the future.

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