Risk Management with Variable Capital Utilization and Procyclical Collateral Capacity*

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Abstract

We build a risk management model that incorporates variable capital utilization and procyclical collateral capacity. The former means that capital utilization determines production, which affects capital depreciation and risk exposure, linking capital utilization to firms' risk management decisions. The latter means that the ability to borrow and hedge increases with expected profitability. Using a new dataset on hedging and capital utilization of oil and gas producers, we employ novel identification strategies and find that hedging is positively correlated with corporate liquidity and expected profitability, whereas utilization is negatively correlated with liquidity. These results support the key predictions of our theory.

Keywords: Corporate hedging, Corporate liquidity, Financial constraints, Expected profitability, Collateral constraint, Procyclical collateral capacity, Variable capital utilization.

JEL Classifications: G23, G30, G32.

We investigate theoretically and empirically how firms manage their cash flow risk based on their liquidity position and expected profitability, when facing financial constraints. Existing theories have highlighted liquidity and expected profitability as the two key determinants of risk management. However, they have not reached a consensus on whether the extent of firms' risk management correlates positively or negatively with corporate liquidity and expected profitability. Financial constraint-based models such as Froot, Scharfstein, and Stein (1993) predict a negative correlation between hedging and liquidity. In contrast, models emphasizing collateral constraints such as Rampini and Viswanathan (2013) predict hedging is positively correlated with liquidity but negatively correlated with expected profitability.[1] Empirically, there is mixed (little) evidence on the relation between hedging and liquidity (expected profitability).

In the first part of the paper, we develop a parsimonious, tractable model that extends existing risk management theories in an important direction. That is, our model recognizes that firms can adjust their production level as part of their risk management strategy to manage their internal liquidity and risk exposure. Specifically, the firm in our model can increase its production level by increasing its capital utilization rate, which increases its capital depreciation rate and exposure to market price risk. This model ingredient is referred to as variable capital utilization (henceforth VCU) in macroeconomics models of business cycle dynamics (e.g. Keynes (1936); Greenwood et al. (1988); Jaimovich and Rebelo (2009)). In our model, VCU links firms' production and capital utilization decisions to risk management decisions through two tradeoffs: an intertemporal tradeoff and a risk-return tradeoff. On the one hand, higher production and capital utilization means higher capital depreciation, leading to lower remaining capital and thus lower future production. This intertemporal

[1] The key intuition of financial constraint-based models is that firms are effectively more risk averse when they are more constrained and thus hedge more; whereas the collateral-constraint based models emphasize that, because both financing for investment and risk management require collateral, firms reduce hedging when the collateral constraint is binding and the opportunity cost of hedging is high in terms of forgone investment.

tradeoff is the focus of the macroeconomics literature featuring VCU. On the other hand, varying production level determines the amount of cash flow risk that needs to be hedged. This risk-return tradeoff is as important as the intertemporal tradeoff in driving the risk management decisions in our model.

By incorporating VCU into a unified risk management model a la Bolton et al. (2011), our model captures the complex interaction between capital utilization and various aspects of firms' risk management, such as liquidity hoarding, production, and financial hedging. When a firm is more financially constrained, it values its current cash flows more than the future ones, leading the firm to increase capital utilization and produce more. At the same time, a more financially constrained firm is more reluctant to bear the additional risk brought by higher production because it is not only more risk-averse but also has fewer resources for hedging. Therefore, the intertemporal tradeoff and the risk-return tradeoff generated by VCU are integrated into firms' risk management decisions, generating the opposing relations between corporate liquidity and capital utilization. An empirical test of this relation is needed to reveal which tradeoff is more dominant in the data. In contrast, the existing risk management models essentially assume constant capital utilization and thus cannot be used to understand the relation between liquidity and capital utilization.

When it comes to risk management through financial instruments, our model also generate new implications on how corporate liquidity and expected profitability affect the financial hedging. Our model predicts an overall positive correlation between hedging and the firm's liquidity, after controlling for the expected profitability. This positive correlation is driven by the collateral constraint, similar to Rampini and Viswanathan (2010, 2013); Bolton et al. (2019). In contrast to these models, our model also predicts a positive correlation between hedging and expected profitability, after controlling for liquidity. This positive correlation is driven by the feature of procyclical collateral capacity (henceforth PCC) in our model, i.e., expected profitability positively affects the collateral capacity for borrowing and hedging. As in the collateral constraint models with persistent profitability, in our model, higher expected profitability means a better investment opportunity, which in turn demands more financing for investment. This channel reduces hedging because hedging and financing competes for limited collateral capacity, as in Rampini and Viswanathan (2010, 2013). Therefore, if the collateral capacity is time-invariant, the relation between expected profitability and hedging is negative. However, with procyclical collateral capacity, our model allows the correlation between hedging and profitability to turn positive if the positive effect of increased collateral capacity on hedging outpaces the negative effect of the investment opportunity channel when the expected profitability is high.

In the second part of the paper, we empirically test these model predictions. We start by constructing a comprehensive panel data set on hedging positions, production, and reserves for independent oil and gas exploration and production (E&P) firms between 2002 and 2016. We document the prevalence and importance of risk management in our sample firms. Less than 10% of the firm-year observations in our sample have zero hedging. Furthermore, firms' hedge ratio, defined as hedging volume divided by production, has substantial variation across firms and over time. The median firm-year hedge ratio is 45% while the standard deviation is almost 32%. We also show that the variation in capital utilization rate is non-trivial in these firms. The ratio of production to proved reserves, our proxy for the utilization rate, has a standard deviation of 7% relative to a mean of 10%.

These firms are chosen as an empirical laboratory to test our theory for the following reasons. First and foremost, data availability remains a major challenge in quantifying hedging (e.g., Guay and Kothari (2003) and Giambona et al. (2018)). We choose E&P firms because they disclose detailed contract-level information on derivative hedges during our sample period, which is not readily available in other industries. Second, the capital utilization rate and the depreciation rate are straightforward to measure for E&P firms as the production uses up the reserves, the main capital of E&P firms, by the same amount (See

Appendix A for an example). We thus define the capital utilization rate as the production to reserves ratio. Third, since the output price risk is the dominant business risk for E&P firms, if the predictions of the risk management theories are true, they should manifest in this sample. Fourth, since our sample firms are within the same industry, the concern that omitted industry characteristics may drive the cross-sectional results is alleviated. Finally, the setting of independent oil and gas producers allows us to identify exogenous shocks to expected profitability and corporate liquidity in novel ways.

Guided by our theory, we construct the empirical counterpart of the key state variables in the model, corporate liquidity and expected profitability. We use the production-weighted futures prices of oil and natural gas as our empirical proxy for expected profitability, which are likely exogenous to an individual firm since it is determined in global commodity markets. To measure corporate liquidity, we use the conventional net cash measure (i.e., cash minus debt) plus *unrealized* hedging gains, which represent the mark-to-market profits on long-term derivative contracts and are a critical component of liquidity in practice for E&P producers. To address the potential endogeneity concern that liquidity can be affected by firm choices outside of our model, we instrument liquidity by the unrealized hedging gains and implement a two-stage least squares (2SLS) estimation. Our identification strategy is based on the observation that unpredictable changes in oil and gas prices cause differential unrealized derivative gains for different pre-existing hedging positions. In the first stage of the 2SLS regression, we find that unrealized hedging gains have a strong positive and significant relation with liquidity, indicating that the instrument is relevant. The 2SLS regression result shows that the hedge ratio has positive and highly significant correlations with both liquidity and output price.

We rule out several alternative explanations for our empirical results. First, since we control for firm-CEO fixed effects in all our empirical specifications, our results cannot be explained by differences in market timing abilities across producers or by differences in managers' preferences regarding hedging. Second, our results remain quantitatively similar for the subsample of shale producers, suggesting that our results are not driven by the difference in drilling technologies. Third, risk-shifting can give rise to a positive correlation between liquidity and hedging if the most distressed firms choose to hedge less (Jensen and Meckling (1976) and Leland (1998)). Following Rampini et al. (2014), we show that risk-shifting does not explain our results since our results remain quantitatively similar even after excluding the most distressed 10% of firms per year in our sample. Fourth, albeit unlikely, there is the concern that our sample firms can influence the oil prices. We address this concern by using the Kilian (2009) index as a proxy of aggregate demand shocks in the oil market to instrument for the oil price. We find the loading on our expected profitability measure remains positive and statistically significant in a 2SLS estimation. Finally, the serial correlation in hedging behavior is unlikely to drive our results because we find similar results when including lagged hedge ratio as a regressor.

We empirically corroborate our model's key mechanisms by testing additional predictions related to the two new features of our model. First, as our model uses the PCC to explain the positive hedging-to-price relation, we test the implication that such relation is more positive for firms with more procyclical collateral capacity. We exploit the unique feature of oil and gas producers that the value of firms' proved undeveloped reserves is more sensitive to changes in oil prices than proved developed reserves. Thus firms with relatively more proved undeveloped reserves have more procyclical collateral capacity. Consistent with our theory prediction, we find that the hedging to oil price relation is indeed more positive for these firms.

Finally, we empirically test the relation between liquidity and the capital utilization rate. As mentioned earlier, the intertemporal tradeoff and the risk-return tradeoff generated by VCU have opposite effects on this relation. We find that liquidity and the capital utilization rate are negatively correlated after controlling for expected profitability, suggesting that the intertemporal tradeoff is more important in our sample. To the best of our knowledge, our paper is the first to document this correlation. Such a relation is not predicted by existing models in which both capital utilization and depreciation rates are constant, thus highlighting the importance of incorporating the VCU feature.

Related Literature

Our model is most closely related to Bolton et al. (2011), a unified framework that includes liquidity management, financing, hedging, and real investment as different aspects of risk management. We also incorporate the collateral constraint from Rampini and Viswanathan (2010, 2013). Bolton et al. (2011) and Rampini and Viswanathan (2010, 2013) are the representative dynamic risk management models in the literature starting from Froot et al. (1993).[2] More recently, Babenko and Tserlukevich (2019) study the relation between hedging and investment by emphasizing the role of real options; Gamba and Triantis (2014) investigate the relation between hedging and liquidity with different degree of operational flexibility; Bolton et al. (2019) explore the systematic and idiosyncratic risk hedging in an optimal contracting model with inalienable human capital. Our paper differs from all these studies as we incorporate endogenous capital utilization through VCU into the unified dynamic risk management framework for the first time in this literature. Our model characterizes the complex interaction between capital utilization and other aspects of risk management in the presence of financial frictions. In addition, our model also highlights the effect of the persistent expected profitability and the related PCC on risk management, which has been discussed by Rampini and Viswanathan (2010) and Bolton et al. (2019). A key contribution of our paper is to demonstrate a tractable way to incorporate VCU and PCC into Bolton et al. (2011) and to characterize the new implications.

[2]Bolton et al. (2011) and Rampini and Viswanathan (2010, 2013) build on various strands of theoretical literature that is too extensive to survey here. For a complete survey of the literature, see reference cited in therein.

Our model is also related to the macroeconomics and finance literature on VCU. In macroeconomics, Keynes (1936) first notices the intertemporal tradeoff in capital utilization, labeling it "user cost of capital". Greenwood et al. (1988) and Jaimovich and Rebelo (2009) among others build on this idea and make it an important ingredient in neoclassical macroeconomic theories to explain business cycles. Recent papers by Garlappi and Song (2017), Ai et al. (2020), Dou et al. (2021), and Grigoris and Segal (2021) explore the asset pricing implications of capital utilization. We contribute to this literature by investigating the implications of VCU for firm risk management, both theoretically and empirically.

Our paper also contributes to the empirical literature starting from Tufano (1996) and Haushalter (2000) that investigates the determinants of the intensive margin of hedging, including but not limited to Jin and Jorion (2006); Carter et al. (2006); Purnanandam (2008); Cheng and Milbradt (2012); Pérez-González and Yun (2013); Gilje and Taillard (2017). Most of these empirical studies rely on a short time series of data and are thus cross-sectional in nature. In contrast, the panel data we construct in this study enables us to control for unobserved time-invariant firm-specific heterogeneity and investigates the average pattern over both bull and bear periods of the oil and gas markets. In this respect, our paper joins the more recent empirical studies that characterize firms' risk management practice using a long time series, such as Kumar and Rabinovitch (2013); Bonaimé et al. (2014); Rampini et al. (2014); Ferriani and Veronese (2019); Babenko et al. (2020). Our paper differs from these studies by testing the new implications of a dynamic risk management model with VCU and PCC.

1. Model

In this section, we present a dynamic risk management model extending the existing theories (Bolton et al. (2011); Rampini and Viswanathan (2010, 2013)) by incorporating VCU and

PCC. The goal of this section is to describe the mechanisms through which the two state variables, corporate liquidity and expected profitability, affect hedging and capital utilization.

1.1. Setup

Production technology We denote by K the physical capital stock of a firm. For oil and gas firms, the main capital stock is the oil and gas reserves. The price of capital is normalized to one. Gross investment to capital rate is denoted by i. Making investment incurs an adjustment cost $\Phi_i(i)K$, where Φ_i is an increasing and convex function. Following the neoclassical q-theory of investment as in Hayashi (1982), we assume that $\Phi_i(i)$ takes the quadratic form of $\frac{1}{2}\phi_i(i-i_0)^2$ with ϕ_i being the investment adjustment coefficient and i_0 the benchmark investment rate.

There are two states of the world, denoted by $s_t \in \{\overline{s}, \underline{s}\}$, with different expected profitability, which are denoted by μ^s with $\mu^{\overline{s}} > \mu^{\underline{s}} > 0$. Throughout the paper, we will call $\overline{s}$ the high state and $\underline{s}$ the low state. The process s_t follows a Markov switching process with $\lambda^s \in \{\lambda^{\overline{s}}, \lambda^{\underline{s}}\}$ being the transition intensity from the current state s to the other state. For example, the intensity $\lambda^{\underline{s}}$ means that there is a probability of $\lambda^{\underline{s}}dt$ that the current state $\underline{s}$ will switch to the other state $\overline{s}$ during a short time dt. The lower the λ^s, the more persistent the state is.

The first novel feature of our model is to endogenize capital utilization and thus production through VCU. To be specific, the firm can choose a capital utilization rate $u_t \in (0,1)$. Given the utilization rate u_t and capital K_t, the production is u_tK_t. The firm's cumulative productivity in current state s is denoted by $A_t^{u,s}$, which evolves according to

$$dA_t^{u,s} = \left[\mu^s u_t - \Phi_u(u_t)\right]dt + u_t\sigma_m dZ_{m,t} + \sigma_f dZ_{f,t},\ t \geq 0, \tag{1}$$

over time increment dt. Correspondingly, the firm's incremental operating cash flows dY_t

within the current state s over time increment dt are given by

$$dY_t = \left[\left(u_t K_t \right) \mu^s - \Phi_u \left(u_t \right) K_t \right] dt + \left(u_t K_t \right) \sigma_m dZ_{m,t} + K_t \sigma_f dZ_{f,t},\ t \geq 0. \tag{2}$$

Here, the first term in the square brackets is the gross profits, $\left(u_t K_t \right) \mu^s$, minus a production adjustment cost, $\Phi_u \left(u_t \right) K_t$. Similar to the investment adjustment cost, $\Phi_u \left(u \right)$ is assumed to take the quadratic form of $\frac{1}{2} \phi_u \left(u - u_0 \right)^2$ with ϕ_u being the production adjustment coefficient and u_0 the benchmark utilization rate of capital.[3]

The second term, $\left(u_t K_t \right) \sigma_m dZ_{m,t}$, is the effect of market risk on firm profits, where the parameter $\sigma_m > 0$ is the state-invariant market volatility and $Z_{m,t}$ is the standard Brownian motion capturing the aggregate market risk. The third term, $K_t \sigma_f dZ_{f,t}$, is the effect of the firm-level idiosyncratic risk, such as operational risks, litigation risks, etc., on firm profits. The standard Brownian motion $Z_{f,t}$ is assumed to be orthogonal to the market risk $Z_{m,t}$ and σ_f is the firm-level idiosyncratic volatility.[4]

Following the VCU literature in macroeconomics (e.g., Keynes (1936); Greenwood et al. (1988)), we assume that a higher utilization rate causes a faster depreciation of the capital stock. For oil and gas producers we study, the capital utilization $u_t K_t$ corresponds to the amount of production, which depletes the existing reserves by the same amount. See Appendix A for an example. Following this literature, we model the capital depreciation rate as $\delta \left(u_t \right)$ (Greenwood et al. (1988)), where the non-negative depreciation function δ is increasing in the utilization rate u. For simplicity, we assume $\delta \left(u_t \right)$ takes the form of $\delta_0 u_t$, where δ_0 is a positive constant. Given the gross investment rate i_t and the utilization rate

[3] If we remove investment adjustment costs, the optimal utilization rate will become a constant when hedging is unconstrained. If we remove utilization adjustment costs, production will be positive infinite if the expected profitability rate exceeds the price of capital, which is 1, or negative infinite otherwise. Either setup does not achieve a well-behaved optimal production policy. So we assume convex adjustment costs on both investment and utilization.

[4] The presence of the idiosyncratic risk is a modeling device to generate precautionary savings even when a firm can perfectly hedge the market risk. This separates the collateral constraint boundary from the payout boundary.

u_t, the accumulation of capital follows

$$dK_t = (i_t - \delta_0 u_t)\, K_t dt,\ t \geq 0. \tag{3}$$

In our model with VCU, the firm faces two important tradeoffs when deciding its utilization rate. First, VCU generates an intertemporal tradeoff as higher production leads to higher current cash flows but lower capital and thus lower future cash flows. Second, the utilization rate determines the production and affects the firm's exposure to the market risk $dZ_{m,t}$, which involves a tradeoff between expected cash flows and risk. For simplicity, we refer to these two tradeoffs as the intertemporal tradeoff and the risk-return tradeoff, respectively. As we discuss later, when our model introduces financial frictions, these two tradeoffs interact with a firm's liquidity position and the optimal hedging policies, making the variable capital utilization an integral part of the firm's risk management decisions.

To our knowledge, we are the first to introduce this VCU mechanism to the corporate finance literature with financial frictions. In the existing models, both capital utilization and depreciation rates are constant. In contrast, the firm in our model can choose its utilization rate, which in turn determines the depreciation rate. Our model nests the commonly used model with "AK" technology and a constant depreciation rate as a special case. When the utilization adjustment coefficient ϕ_u approaches to positive infinity, a firm in our model would optimally choose a constant utilization rate u_0, resulting in a constant depreciation rate of $\delta_0 u_0$. The firm's profitability rate $dA_t^{0,s}$ in state s is

$$dA_t^{0,s} = \mu^s u_0 dt + \sigma_m u_0 dZ_{m,t} + \sigma_f dZ_{f,t},\ t \geq 0, \tag{4}$$

which is similar to the setup in Bolton et al. (2011). The macroeconomic literature has highlighted the importance of the VCU mechanism for understanding the business cycle. We show in later sections that incorporating the VCU mechanism into the existing risk management models is important to understand the dynamics of hedging and production under financial frictions.

Financing and risk management with financial frictions The firm in our model faces financial frictions so it has an incentive to hoard liquidity and manage risk. We assume that the firm finances its operations by saving internally or borrowing risk-free debt from risk-neutral lenders. However, due to financial frictions, the firm cannot raise new external equity and is subject to a collateral constraint that limits its ability to borrow and hedge. Furthermore, if the firm's borrowing reaches the maximum collateral capacity, it has to liquidate its capital with a fire-sale discount. We first introduce the ideas of liquidity and hedging, then discuss the collateral constraint and the forced liquidation.

We denote by W_t liquidity of the firm, which is defined as cash, short-term investments, and unrealized hedging gains and losses net of its borrowing. When W_t is positive, cash is the marginal source of financing; when W_t is negative, debt is the marginal source of financing. Liquidity W_t evolves according to

$$dW_t = dY_t - \left(i_t + \frac{\phi_i}{2}\left(i - i_0\right)^2\right) K_t dt + r_w W_t dt - dF_t + d\Pi_{H,t}\,. \tag{5}$$

Here, the first term is the operating cash flows; the second term in the parentheses is the investment cash flows, or the total investment costs. The term $r_w W_t$ is the interest earned (when $W_t > 0$) or paid (when $W_t < 0$) on W_t. Following Bolton et al. (2011), Rampini and Viswanathan (2010, 2013) and Li et al. (2016), we assume the interest rate r_w on liquidity is positive but lower than the risk-free rate r because of corporate taxes. The next term dF_t denotes the dividend payment to the shareholders, where F_t is the cumulative dividend payouts.

The last term $d\Pi_{H,t}$ is the instantaneous hedging profits. Let H_t be the hedging position a firm takes to hedge the market risk $dZ_{m,t}$. Without loss of generality, we assume that H

has a negative loading on the market risk $dZ_{m,t}$. As a result, the firm has overall exposure of $u_t K_t - H_t$ to the aggregate diffusion shock $\sigma_m dZ_{m,t}$. The hedging profits follow

$$d\Pi_{H,t} = -H_t \sigma_m dZ_{m,t} \,. \tag{6}$$

We assume that the firm cannot hedge the regime-switching risk in μ^s and the firm-level idiosyncratic risk $dZ_{f,t}$ because in practice it is difficult to find a counterparty for such hedging contracts.

The firm faces a collateral constraint,

$$\theta^s K_t \geq -W_t + \pi \left| H_t \right| \,. \tag{7}$$

Here θ^s is the collateral capacity. The margin requirement is denoted by π. The collateral constraint is motivated by the fact that both borrowing and hedging require collateral as in Rampini and Viswanathan (2010, 2013).[5] Our specification of the collateral constraint extends the margin requirement constraint in Bolton et al. (2011), which is a special case of our model with $\theta^s = 0$. There, the firm needs to use cash as collateral for its hedging position and thus when W_t goes down to zero and the hedging goes to zero as well. In contrast, in our model, the firm can use its capital as the collateral for borrowing and hedging. Thus, the firm can borrow ($W_t < 0$) and hedge at the same time. Our assumption fits the common practice in the oil and gas industry that the ability of a firm to enter a hedging position depends on $\theta^s K_t + W_t$ rather than just W_t. Furthermore, we assume $\theta^{\overline{s}} > \theta^{\underline{s}} > 0$, so the lenders are more willing to lend to the firms when the expected profitability is high. Such a procyclical collateral constraint is also featured in Kehoe and Levine (1993).

Finally, like Bolton et al. (2011), we assume that when the firm violates the collateral

[5] Hedging competes with borrowing for collateral because the derivative counterparties enjoy "effective seniority" relative to debt claims in bankruptcy under U.S. bankruptcy law (Bolton and Oehmke (2015)). Thus the collateral available for creditors is the total collateral minus that owed to the hedging counterparties.

constraint, it has to liquidate its capital K_t at a fire-sale price l, pay back its debt $-W_t$ when $W_t < 0$, and close its hedging position H_t. Here, $l \in (0, 1)$ is the liquidation value of capital. After liquidation, the firm's shareholders end up with $lK_t + W_t$. We assume that the liquidation value l is much higher than the collateral capacity θ^s in both states. So in our model, the shareholders' payoffs are always positive even after liquidation, and the debt $-W_t$ can always be fully repaid.[6] This guarantees that the debt in our model is risk-free.

1.2. The Firm's Problem

The firm's problem is to maximize its shareholder value, which is the expected sum of discounted dividends:

$$V\left(K_t, W_t, s\right) = \max_{\{i_\tau, u_\tau, H_\tau, F_\tau\}_{\tau \geq t}} \mathbb{E}\left\{\int_0^\infty e^{-r\tau} dF_{t+\tau}\right\},$$

given (3), (5), (7), and the non-negative dividend payment constraint $dF_t \geq 0$ for all time t.

Before the firm pays out or is liquidated, the Hamilton-Jacobi-Bellman (HJB) equation is

$$\begin{aligned} rV\left(K_t, W_t, s\right) = \max_{i_t, u_t, H_t} & \left[\mu^s u_t - \frac{\phi_u}{2}\left(u_t - u_0\right)^2 - i_t - \frac{\phi_i}{2}\left(i - i_0\right)^2\right] K_t V_W + r_w W_t V_W \\ & + \left(i_t - \delta_0 u_t\right) K_t V_K + \frac{1}{2}\left[\sigma_m^2 \left(u_t K_t - H_t\right)^2 + \sigma_f^2 K_t^2\right] V_{WW} \\ & + \lambda\left[V\left(K_t, W_t, \widetilde{s}\right) - V\left(K_t, W_t, s\right)\right], \end{aligned}$$

where $\widetilde{s}$ denotes the state different from the current state s.

[6] In our model, as long as $l > \theta^{\overline{s}}$, the debt can always be fully repaid in both states.

Boundary conditions We denote the payout boundary by $\overline{W}(K,s)$, which satisfies

$$V_W\left(K_t,\overline{W}(K,s),s\right)=1\,,$$
$$V_{WW}\left(K_t,\overline{W}(K,s),s\right)=0\,.$$

The first boundary condition says the marginal value of liquidity is the same as the outside money, which is 1. The second boundary condition is the "super contact" condition because the payout boundary $\overline{W}(K,s)$ is optimally chosen (Dumas (1991); Bolton et al. (2011)).

The liquidation boundary is $\underline{W}(K,s)=-\theta^s K$.

$$V(K_t,W_t,s)=lK_t+W_t,\ \forall W_t\leq\underline{W}(K,s)\ .$$

This equation says, when the firm's borrowing exceeds its collateral capacity θ^s, the shareholders have to liquidate the firm capital at a fire-sale price l ($l<1$) and pay back the existing debt $-W_t$.

Constant return to scale Our model is by design homogeneous of degree one with respect to the state variables (K_t,W_t) and control variables (H_t,F_t). We scale the following variables and value function by the capital K,

$$w\equiv\frac{W}{K},$$
$$v^s(w)\equiv\frac{1}{K}V(K,W,s)=V(1,w,s)\ .$$

The hedge ratio is defined as the hedging position scaled by the production, which is equal to capital utilization uK,

$$h\equiv H/(uK)\,.$$

The scaled HJB equation is an ordinary differential equation (ODE),

$$(r+\delta_0 u-i)\,v^s(w)=\max_{y,i,h}\left\{\left[(r_w+\delta_0 u-i)\,w-i-\frac{\phi_i}{2}(i-i_0)^2+\mu^s u-\frac{\phi_u}{2}(u-u_0)^2\right]v^s_w(w)\right.$$
$$\left.+\frac{1}{2}\left[\sigma_m^2 u^2(1-h)^2+\sigma_f^2\right]v^s_{ww}(w)+\lambda^s\left[v^{\tilde{s}}(w)-v^s(w)\right]\right\}, \qquad (8)$$

with the collateral constraint

$$\theta^s \geq -w_t+\pi\left|h_t u_t\right|, \qquad (9)$$

and boundary conditions

$$v^s_w\left(\overline{w}^s\right)=1\,, \qquad (10)$$

$$v^s_{ww}\left(\overline{w}^s\right)=0\,, \qquad (11)$$

$$v^s(w)=l+w\,,\ \forall w\leq -\theta^s\,. \qquad (12)$$

Given the feature of constant return to scale in our model, the scaled net worth x_t is defined as

$$x_t\equiv\left(W_t+K_t\right)/K_t=w_t+1,$$

which is an equivalent state variable to w_t. This connects our model to the models in Rampini and Viswanathan (2010, 2013).

1.3. *Analytical Implications*

We derive the first-order conditions of the problem (8), which deliver the optimal policies of investment, production, and hedging:

$$i^*(w,s) = i_0 + \frac{1}{\phi_i}\left(\frac{v^s}{v^s_w} - w - 1\right), \tag{13}$$

$$u^*(w,s) = \frac{(\delta_0 w + \mu^s + \phi_u u_0) - \delta_0 \frac{v^s}{v^s_w}}{\phi_u - \sigma_m^2 (1 - h^*(w))^2 \frac{v^s_{ww}}{v^s_w}}, \tag{14}$$

$$h^*(w,s) = \min\left\{1, \frac{\theta^s + w}{\pi u^*(w,s)}\right\}. \tag{15}$$

The optimal investment given in (13) is the same as that in Bolton et al. (2011). It can be rewritten as

$$1 + \phi_i (i^* - i_0) = \frac{v^s - w v^s_w}{v^s_w}. \tag{16}$$

The left side is the marginal cost of investment. On the right side, $v^s - wv^s_w$ is the marginal value of capital in our constant return to scale setting, or the marginal q and v^s_w is the marginal value of liquidity. So, the optimal investment is determined by equating the marginal cost of investment to the ratio of the marginal q to the marginal cost of financing this investment.

The solutions of utilization rate and hedging given in (14) and (15) depend on whether or not the collateral constraint is binding. When the collateral constraint is binding, the firm does not have sufficient collateral to support the full hedging on the market risk associated with the production, i.e., $h^*(w,s) = \frac{\theta^s + w}{\pi u^*(w,s)} < 1$. In the following discussion, we assume that the firm's value function is increasing and concave, which we verify quantitatively in the numerical solution part. When choosing the optimal utilization in this case, the firm considers the two tradeoffs generated by VCU.

First, the intertemporal tradeoff, captured by the numerator of u^* in (14), leads to a negative relation between utilization and w.[7] The intuition is that when the firm is financially constrained, its marginal value of liquidity is greater than one and it values current cash flows more than future cash flows. Consequently, a firm is willing to produce more now at the expense of less capital for future production. If the firm value is concave, a lower w leads to a higher marginal value of liquidity, and thus a higher incentive for the firm to produce more now.

Second, the risk-return tradeoff, captured by the denominator of u^* in (14), leads to a positive relation between utilization and w. To see this point, we can interpret $\gamma_e \equiv -v^s_{ww}/v^s_w$ as the effective absolute risk aversion induced by the financial constraint. A lower w is associated with a higher effective risk aversion, which makes the firm less willing to accept the risk-return tradeoff brought by production. Therefore, the two tradeoffs generate opposite effects on the relation between utilization and liquidity. The resulting relation therefore depends on which effect is more important.

When the collateral constraint is not binding, the firm can fully hedge all the market risks caused by production and we have $h^*(w,s) = 1$ in (15). That is, the unconstrained optimal hedge ratio is one. In this case, the risk-return tradeoff captured by the denominator of u^* in (14) is no longer in effect. In this case, the optimal utilization only depends on the intertemporal tradeoff, which leads to a negative relation between capital utilization and liquidity.

In sum, we can see that the firm's capital utilization decision and its hedging decision are closely related once we introduce the VCU feature in presence of financial frictions.

[7] To see this point, note that the numerator on the right of (14) has a derivative of $v^s v^s_{ww}/(v^s_w)^2$ with respect to the scaled liquidity w.

1.4. Solution and Implications

We solve our model numerically to investigate its quantitative implications in Figure 1. Although our theoretical framework applies generally, we base our calibration of parameters on the related empirical moments of our sample of oil and gas producers because we want to empirically test our model implications in the sample later. Our calibration is reported in Table 1 and its details are discussed in Appendix B.

Panel A plots the value functions $v^s(w)$ of the firm in two profitability states. The horizontal axis is for liquidity w. The value function is higher in the high state $s = \overline{s}$ (blue solid curve) than in the low profitability state $s = \underline{s}$ (red dashed curve). In both states, the value functions are concave within the liquidation and payout boundaries. However, the value function is linear in the low state when liquidity is below the liquidation boundary $\underline{w}^{\underline{s}}$. This occurs when the firm gets into the low state from the high state with liquidity $w \in [\underline{w}^{\overline{s}}, \underline{w}^{\underline{s}})$, the firm immediately liquidates. In this case, the shareholders only receive the liquidation payoff $lq^{\underline{s}} + w$, which is linear in w for $w \in [\underline{w}^{\overline{s}}, \underline{w}^{\underline{s}})$.

Panel B plots the marginal value of liquidity $v^s_w(w)$ in both states, respectively. In both states, the marginal value of liquidity obtains its maximum when w approaches the liquidation boundary from the right. As w increases, the marginal value gradually decreases. In the payout region (when $w \geq \overline{w}^s$), the marginal value of liquidity is one. The patterns of the marginal value of liquidity also indicate that the value function is concave with respect to liquidity, which is consistent with Bolton et al. (2011).

Panel C is the optimal investment $i^*(w)$. As expected from the first order condition of investment in (13), the investment is increasing with liquidity. Moreover, the optimal investment is higher in the high state because the investment opportunity is better due to higher expected future profitability and the time-invariant investment cost.

Panel D plots the effective absolute risk aversion $\gamma_e \equiv -\frac{v^s_{ww}(w)}{v^s_w(w)}$. Overall, γ_e decreases with liquidity w in both states, suggesting a more financially constrained firm has a higher effective risk aversion. Therefore, the hedging demand in our model is similar to that in Froot et al. (1993): more financially constrained firms are effectively more risk-averse and thus, desire a higher hedge ratio.

Panels E presents the optimal hedge ratio $h^*(w,s)$. We first discuss the relation between hedging and liquidity w. There are two main competing channels driving this relation. First, as discussed above, the effective risk aversion in our model generates a positive relation between hedging and liquidity as the more financially constrained firms are effectively more risk-averse and desire more hedging. Second, the collateral constraint in our model limits the firm's ability to hedge, as shown in (9), which in turn depends positively on liquidity. These two channels generate opposite effects of liquidity on hedging. In Panel E, $\hat{w}^s$ denotes the binding collateral constraint cutoff, above which the collateral constraint is not binding and the risk aversion channel dominates. In this region where $w > \hat{w}^s$, the firm achieves the unconstrained optimal hedging $h^* = 1$.[8] In the region where $w < \hat{w}^s$, the hedging is constrained by the collateral constraint (9) and thus $h^*(w,s) = \frac{\theta^s + w}{\pi u^*(w,s)}$. In this region, the constrained optimal hedging is increasing with liquidity even when the desire for hedging is decreasing with liquidity. This illustrates the paradox noted by Stulz (1996): more financially constrained firms want to hedge more in theory but fail to do so in practice. We explain such a paradox by the collateral constraint, consistent with Bolton et al. (2011) and Rampini and Viswanathan (2010, 2013).

In Panel E, the optimal hedging policies are higher in the high profitability state than in the low profitability state. Holding liquidity w constant, the relation between hedging and the expected profitability is determined by three channels. The first one is the investment opportunity channel. As in Rampini and Viswanathan (2013), high expected profitability

[8] In our model, the hedge ratio is scaled by the utilization or production. If the hedge ratio is scaled by the capital K instead, the hedging-to-capital ratio (h^*u^*) will be decreasing with liquidity in this region. This is because u^* is decreasing with liquidity, as shown in Panel F.

means a better investment opportunity, which in turn demands more financing. When the collateral capacity does not increase with profitability, this channel will lead to a reduced hedging when profitability is high.[9] The second channel is the PCC channel. In our model, the collateral capacity θ^s is increasing with profitability state. When the positive effect of increased collateral capacity on hedging outpaces the negative effect of increased financing needs for investment in the high state, the correlation between hedging and expected profitability turns positive. The third channel is related to the capital utilization: Higher utilization leads to more production and thus higher exposure to the market price risk, which motivates the firm to hedge more. Since we follow the empirical literature and define the hedge ratio as hedging scaled by production, the resulting hedge ratio is mainly driven by the first two channels. In our calibrated results, the PCC channel dominates the investment opportunity channel, and thus the optimal hedging is increasing in expected profitability.

Panel F plots the optimal capital utilization rate $u^*(w, s)$. Consistent with our discussion in Subsection 1.3, when the hedging is unconstrained ($w \geq \hat{w}^s$), the utilization rate is negatively correlated with liquidity w in both profitability states because of the intertemporal tradeoff. However, when the hedging is constrained by the collateral capacity ($w < \hat{w}^s$), the market risk exposure associated with higher utilization that cannot be fully hedged. This risk-return tradeoff becomes more important in low liquidity region as the firm becomes more risk averse, as illustrated by Panel D. Consequently the firm becomes more reluctant to increase utilization in this region ($w < \hat{w}^s$). Such effect explains why the slope of the utilization with respect to w becomes flatter as liquidity decreases from $\hat{w}^s$.[10]

[9] It is possible that higher profitability also leads to higher capital prices and thus higher investment costs. This would weaken the investment opportunity channel.

[10] If we increase the volatility of market risk in the calibration, the risk-return tradeoff can dominate the intertemporal tradeoff and the capital utilization rate becomes increasing with liquidity when w is extremely low. See Appendix C for an example.

1.5. Testable Implications

We summarize the testable implications on hedging below:

H1 Our model predicts an overall positive correlation between hedge ratio and the firm's liquidity given expected profitability, similar to Rampini and Viswanathan (2010, 2013); Rampini et al. (2014); Bolton et al. (2019). If the collateral constraint is not present or its effects are not strong enough, the relation between the hedge ratio and liquidity can be negative (Froot et al. (1993)) or non-monotonic (Purnanandam (2008); Bolton et al. (2011)).

H2(i) Our calibrated model predicts a positive correlation between hedge ratio and expected profitability given liquidity when the expected profitability is persistent. As we have discussed in Subsection 1.4, this occurs when the positive correlation induced by the PCC effect dominates the negative correlation induced by the investment opportunity effect. If the collateral capacity is time-invariant as in Rampini and Viswanathan (2010, 2013), then the PCC effect is shut down and the hedge ratio becomes negatively correlated with the expected profitability. We emphasize the importance of controlling for the effect of liquidity on hedging, because the liquidity position includes the cumulative effect of realized operating cash flows, investment cash flows, and hedging profits, all of which are correlated with the persistent expected profitability.

H2(ii) The procyclical capacity is the main driving force of the positive correlation between the expected profitability and hedging in our calibrated model, so we expect this positive relation to be stronger among firms with more procyclical collateral capacity.

H3 Our model predicts that given the expected profitability, the overall correlation between the capital utilization rate and liquidity depends on the competing effects of the intertemporal tradeoff and risk-return tradeoff introduced by VCU. When the former dominates the latter as under our calibration, the correlation is negative. Without the feature of VCU, the capital utilization rate is a constant and does not depend on liquidity, similar to that in the existing models.

2. Empirical Design and Data

In this section, we describe in detail the construction of our dataset on firms' capital utilization, production, and hedging. We then discuss our empirical strategy to assess how corporate liquidity and expected profitability, the two state variables in the model, affect hedging and capital utilization.

Our sample comprises publicly traded independent oil and gas producers. This sample is appealing to test our model for several reasons. First, we can quantify the degree to which these firms hedge their output price risk because of the detailed contract-level disclosure they make. Second, since the output price risk is the main business risk for these firms, risk management should a priori be an important consideration for this sample of firms. Third, studying firms in the same industry helps rule out industry-level explanations for the results we document. Finally, connecting firms' capital utilization rate and capital depreciation rate in the VCU mechanism is straightforward for E&P firms, despite being a challenging task in many other settings. This is because the proved reserves are the dominant capital of E&P firms and production of oil and gas uses up this capital by the same amount. We provide a real world example to illustrate that the depletion of the proved reserve is equal to the production using the 2006 10-K filing of Chesapeake Energy Corporation in Appendix A.

2.1. Data

We collect hedging data from 10-K filings of public independent oil and gas producers in the U.S. The sample period is between 2002 and 2016 due to hedging data availability. Financial reporting standards for derivative instruments are formally established only after Statements of Financial Accounting Standards No. 133 (SFAS 133). Prior to SFAS 133, commodity related derivatives that have physical settlements are not required to be disclosed. After SFAS 133, firms are required to disclose all derivative positions on the balance sheet and the changes in their fair value in the income statement or shareholders' equity, including the ones used for hedging activities.[11] SFAS 133 is effective for fiscal years beginning after June 2000 and all of our sample companies adopted this standard by 2002. We exclude integrated oil and gas producers, because their refinery segment serves as an operational hedge for the exploration and production segment and thus greatly complicates the calculation of hedge ratio. In contrast, independent oil and gas producers rely almost exclusively on derivative contracts for hedging. Therefore, we measure hedge ratio by fraction of production that is hedged by derivative contracts to test our model predictions. Appendix D describes the hedging data collection process in detail.

We collect product-level production, proved reserves, and breakdown of changes in proved reserves at the firm level from Bloomberg. Our measure of the capital utilization rate is the production to proved reserves ratio.[12] Our measure of the procyclicality of the collateral constraint is the ratio of the proved undeveloped reserves to the total proved reserves, because the former is more positively correlated with the commodity price as discussed later in

[11] Although SFAS 105 requires firms to disclose the face value, contract types, or notional amount of financial instruments with off-balance-sheet risk of accounting loss since 1990, commodity and other derivatives that involve physical settlement were exempted from disclosure requirements until the implementation of SFAS 133. As a result, early empirical studies on oil and gas firms' hedging policies have to rely on data from surveys and voluntary disclosures.

[12] Oil and gas firms also own unproved reserves, which are reserves that are much less likely to be recovered than the proved reserves due to technological or economic uncertainties. We use proved reserves as the denominator for the utilization rate for three reasons. First, by definition, unproved reserves cannot be directly used for production, i.e., they are not utilizable. Second, production is subtracted from proved reserves as depletion, not from unproved reserves (as shown in Appendix A), so the intertemporal tradeoff does not apply to the unproved reserves. Third, according to the SEC rules "Modernization of Oil and Gas Reporting", detailed disclosure on proved reserves is mandatory, while that on unproved reserves is optional. All of our sample firms report detailed information on proved reserves, while very few firms report their unproved reserves.

Subsection 3.4. We obtain the futures price for the front month contract for West Texas Intermediate (WTI) crude oil, and Henry Hub natural gas from the U.S. Energy Information Administration. We collect financial data from Compustat. Table 2 reports how we define and construct our key empirical variables.

Table 3 presents summary statistics on our final sample of 851 firm-year observations covering 104 unique firms. The median hedge ratio is 0.452, which is higher than the ratio found in prior studies (Haushalter (2000); Jin and Jorion (2006)). This is partly due to the difference in sample periods and partly due to our exclusion of integrated oil and gas producers whose refinery business serves as an operational hedge making them less reliant on financial hedges. Only about 10% of firm-years in our sample have a hedge ratio equal to zero, suggesting that the majority of firms in our sample actively manage output price risk. Figure 2 plots the average hedge ratio and the average price, for oil and natural gas separately, in each year of our sample. It shows that oil and gas markets experience both bull and bear periods during our sample period. We also find significant variation in utilization rate for our sample firms. For the median firm-year, production averages 8.7% of reserves while the standard deviation of the utilization rate is 7.1%.

Table 3 also shows the financial characteristics of our sample firms. The median book asset value is $1.87 billion. These companies are profitable with a median operating profitability of 13.7%. At the same time, the median cash holding of these companies is only 1.6%, the book leverage is 30.6%, and a dividend is paid in about 55% of all firm-years. These numbers suggest that oil and gas producers have substantial leverage and save relatively little in cash.

2.2. Empirical Design

Our empirical strategy is guided by the testable implications discussed in Section 1. The two key state variables in our theory are corporate liquidity and expected profitability, which jointly determine firms' hedge ratio and utilization rate. We first discuss how we measure these two state variables and then explain our identification strategy.

The corporate liquidity measure in our model is defined as cash, short-term investments, and unrealized hedging gains and losses, net of its borrowing. Our corresponding empirical measure is Compustat cash and short-term investments (*che*), plus our hand collected unrealized hedging gains and losses, minus Compustat long-term debt (*dltt*) and debt in current liabilities (*dlc*) scaled by total assets. Our liquidity measure is the same as the commonly used net cash measure as in Hennessy and Whited (2007) and Warusawitharana and Whited (2015), except that we supplement it with the unrealized hedging gains and losses.[13] We do that for two important reasons: First, our model considers hedging while theirs do not, making the inclusion of the hedging profits necessarily. Second, oil and gas firms hedge a substantial portion of their production, and thus hedging gains and losses are a critical component of their liquidity in practice.

We proxy for the expected profitability with the latest oil and gas futures price price given that changes in oil and gas futures price are largely unpredictable. Since our sample firms often produce both oil and natural gas, we use the weighted futures price at the firm-year level with the weights being the firm's production of the two commodities.

While our empirical proxy for expected profitability, the prices of oil and natural gas, is likely to be exogenous,[14] there is a concern that liquidity and hedging can be simultaneously affected by an omitted variable not modeled in our theory. We address this concern by employing unrealized hedging gains as a novel instrument for liquidity. Unrealized hedging gains are mark-to-market profits on long-term (longer than one year) derivative contracts that are

[13] The realized hedging gains and losses are already reflected in Compustat cash and short-term investments (*che*).

[14] Oil and gas prices are determined in the global market where the independent E&P firms in our sample are price-takers. Therefore, it is reasonable to assume that our sample firms make production and hedging decisions given the commodity price. Nevertheless, in our robustness tests we address the reverse causality concern that these firms can manipulate the commodity price by changing their production and hedging policies.

still outstanding at the end of the fiscal year. Because exogenous changes in commodity prices result in unpredictable gains and losses on pre-existing hedging positions established at different points of time during the past fiscal year, we use unrealized hedging gains are an exogenous source of variation in liquidity. For unrealized hedging gains to be a plausible instrument for liquidity, the exclusion restriction and relevance condition must be satisfied. The unpredictable nature of unrealized hedging gains[15] ensures that they are plausibly orthogonal to omitted firm choice variables that might affect hedging (exclusion). The mark-to-market nature of these derivative contracts means that unrealized hedging gains can be readily converted into cash and thus are part of the firm's liquidity position (relevance). Furthermore, we use unrealized but not realized hedging gains as an instrument for liquidity because the realized hedging gains are offset by the realized profits from the production it hedges. See Appendix D.3 for a more detailed discussion of this point. In our sample, the median unrealized hedging gain is about zero while its standard deviation is 4.5% of assets (see Table 3). This suggests that firms cannot predict these gains and that there is substantial variation in their quantities.

3. Testing Model Predictions

3.1. The Effects of Corporate Liquidity and Expected Profitability on Hedging

To test the theoretical predictions in Hypotheses H1 and H2(i) stated in Subsection 1.5, we start by estimating the following linear model with ordinary least squares (OLS) :

[15] We are not aware of any empirical evidence showing that oil and gas producers have superior ability in timing the commodity derivatives markets. In theory, risk-averse hedgers in equilibrium should pay instead of earn the risk premium (Acharya et al. (2013)), which is also supported by the negative average unrealized gains in the summary statistics in Table 3.

$$\text{Hedge Ratio}_{i,t+1} = \alpha + \beta_1 \text{Liquidity}_{it} + \beta_2 \text{Output Price}_{it} + \gamma_i + \varepsilon_{it}\,. \tag{17}$$

The dependent variable is the fraction of production that is hedged (Haushalter (2000); Jin and Jorion (2006)). Specifically, we define Hedge Ratio$_{i,t+1}$ as the amount of the next-year production hedged based on derivative contracts reported at the firm i's fiscal-year end, scaled by the production in year t. Following Almeida et al. (2019), we also take into account the fixed-price physical delivery contracts between the producers and customers. Liquidity$_{it}$, discussed in the previous section, is net cash plus unrealized hedging gains scaled by total assets. Output Price$_{it}$ is our empirical proxy for expected profitability, which is the log of the production-weighted oil and gas futures price. The regression includes firm-CEO fixed effects, γ_i, to account for time-invariant firm characteristics as well as managerial skill and preferences. The standard errors are clustered at both the year and firm levels. Since liquidity and expected profitability jointly determine firms' hedge ratio and utilization rate in our model, it is important to note that our test of the effect of one state variable on hedging is conditional on controlling for the other state variable. For example, as we emphasize in H2(i), our prediction of a positive hedging-expected profitability relation is conditional on controlling for liquidity because the liquidity position includes the cumulative effect of realized operating cash flows, investment cash flows, and hedging profits, all of which are correlated with the persistent expected profitability.

The results are presented in Table 4. Column (1) shows the estimates from an OLS regression of hedge ratio on liquidity and the output price. We find that the coefficients on both key independent variables are positive, consistent with Hypotheses H1 and H2(i). The coefficient on the output price is statistically significant, while the coefficient on liquidity is not.

As we explain in Subection 2.2, the coefficient estimate on liquidity in Column (1) might be subject to an omitted variable concern. We resolve this endogeneity issue by using unrealized hedging gains as a novel instrument for our liquidity measure. We first run a reduced-form model in which we include unrealized hedging gains as an independent variable in place of liquidity. These results are presented in Column (2) of Table 4. The coefficient on unrealized hedging gains is positive and now significant at the 5% level, supporting H1.

Next, we conduct a two-stage least squares (2SLS) analysis. In Column (3) of Table 4, we present the first stage of the two-stage estimation by showing the results from an OLS regression of liquidity on unrealized hedging gains. The coefficient on unrealized hedging gains is positive and significant at the 1% level. The F-statistic of 42 in the first stage of the 2SLS regression exceeds the threshold of ten, suggesting that our instrument is unlikely to be weak (Staiger and Stock (1997)). This result verifies the relevance condition for a valid instrument.

In Column (4), we present the 2SLS results where liquidity is instrumented by unrealized hedging gains. The coefficients on both the instrumented liquidity and output price are positive and statistically significant at the 5% level, supporting both H1 and H2(i). The economic magnitude of these coefficient estimates is also substantial. Based on the summary statistics from Table 3, we calculate that a one standard deviation increase in the log price of 0.414 leads to an increase in hedge ratio of 5.1 percentage points (pp) and a one standard deviation increase in liquidity of 0.267 leads to an increase in hedge ratio of 9.1 pp.[16] The magnitude of the regression coefficient on liquidity is larger in the 2SLS estimation than that of the OLS estimates. This is likely because the instrument better isolates a source of variation in liquidity that is relevant to hedging behavior.

The relation between hedging and liquidity is driven by two channels in our model. As discussed in Subsection 1.5, the risk aversion channel predicts a negative relation (Froot

[16] Rampini et al. (2014) find a slightly more positive relation between liquidity and hedge ratio for the airline firms, in which one standard deviation increase in liquidity increases the hedge ratio of fuel expenses by about 20 pp.

et al. (1993)), whereas the collateral constraint channel predicts the opposite (Rampini and Viswanathan (2010, 2013), Bolton et al. (2011)). Our empirical evidence of a positive relation between liquidity and hedging shows that the collateral constraint channel dominates the risk aversion channel for oil and gas producers in our sample. Our empirical results support the theoretical insight that the collateral constraint is quantitatively and qualitatively important to explain the relation between hedging and liquidity.

The relation between hedging and expected profitability is affected by the investment opportunity channel and the PCC channel in the model. As discussed in Subsection 1.5, when the latter channel is not present, Rampini and Viswanathan (2013) predicts a negative correlation between expected profitability and hedging when expected profitability is persistent and collateral capacity is time-invariant. Our finding of a positive relation in the data suggests that the PCC channel in our model is important to explain the relation between expected profitability and hedging in the data.

3.2. Robustness Tests

In Table 5, we examine the robustness of our results to an alternative empirical measure of liquidity. We discuss in Section 1 that our model can be reformatted using the scaled net worth to replace liquidity as the state variable. Therefore, we use the book value of shareholder equity scaled by the total asset as an alternative measure.[17] The results from both the OLS (Column (1)) and the 2SLS specifications (Column (4)) suggest that net worth is positively and significantly associated with hedge ratio, consistent with Hypothesis H1.

However, the relationship between hedging and expected profitability is statistically insignificant in the 2SLS regression in Column (4) though it is positive and significant in the OLS regression in Column (1). This difference arises since book equity is not a perfect

[17] We do not need to augment the shareholder equity with unrealized hedging gains because, unlike in the case with net cash, unrealized hedging gains are already included in shareholder equity.

measure of the scaled net worth in the model. Specifically, unlike the scaled net worth in the model, the book equity is directly correlated with the commodity price because oil and gas firms have to write off a part of their reserves when prices are low.[18] Given the positive correlation between book equity and the output prices, when we regress the book equity and the output prices together in the same equation, the former will absorb part of the effects of the prices on hedging, leading to an attenuated coefficient on the price. To validate this intuition, we control for asset write-offs (proxied by the revisions in proved reserves) in the same regressions in Appendix Table X1. Controlling for write-offs, we find that the coefficients on output price become statistically significant.

During our sample period, the U.S. became one of the world's largest oil producers due to the breakthrough in oil and gas production technology referred to as the "Shale Revolution." Shale producers use a combination of horizontal drilling and hydraulic fracturing to produce oil and gas, which is more flexible compared to the conventional production technology (e.g., Bjørnland et al. (2017)). Lower adjustment cost for production makes the VCU feature more relevant in the shale producer context. Therefore, we expect to find positive relations between hedging and liquidity even when we restrict our sample to a smaller set of shale producers.

To test this prediction, we identify shale producers in each year of our sample period by checking whether their 10-K statements mention production in at least one of the following major shale play areas: Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, the Permian Basin, and Utica.[19] In Table 6, we present results from our base specifications with the sample restricted to those firm-years in which the firm is a shale producer. These results are very similar to our base results in Table 4. In the OLS regressions, the relation between hedging and liquidity (price) is positive and is statistically insignificant (significant). Column

[18] See the Appendix A for an example of asset impairment due to low output price.

[19] The list of major shale play areas is from the U.S. Energy Information Administration: https://www.eia.gov/todayinenergy/detail.php?id=38372.

(2) shows the reduced form regression in which unrealized hedging gains is used in place of liquidity. We find that the coefficient is positive and significant. Column (4) shows the 2SLS results in which we instrument liquidity with unrealized hedging gains. We again find a positive and significant relation between hedging and liquidity (price).

3.3. Alternative Explanations

In this subsection, we consider several alternative explanations for why the hedge ratio is positively correlated with corporate liquidity and expected profitability.

First, the positive relation between hedge ratio and liquidity can arise if managers of firms with high liquidity are more sophisticated at hedging or they have a stronger preference for hedging. Including firm-CEO fixed effects controls for such time-invariant characteristics. Therefore, manager sophistication and preferences studied in Kumar and Rabinovitch (2013); Bakke et al. (2016) are unlikely to explain our results.

Second, a potential explanation for why the hedge ratio is positively related to the output price and liquidity is risk-shifting (Jensen and Meckling (1976) and Leland (1998)). Under this explanation, when the output price is low, or the internal liquidity is low, financially distressed firms have an incentive to take more risks by hedging less, leading to positive hedging-to-price and positive hedging-to-liquidity relations. To show that this risk-shifting theory does not drive our results entirely, we run a robustness test in which we exclude the most distressed firms by filtering out the bottom 10% of observations each year based on the Altman Z-Score. The results in Table 8 show that the magnitude and statistical significance of the key variables are very similar to our main results. The 2SLS coefficient on liquidity is almost identical to that in Table 4 and significant at the 5% level, and so is the 2SLS coefficient on output price. These results suggest that risk-shifting is unlikely to fully explain our findings.

Third, there is a potential reverse causality concern about the positive relation between hedge ratio and our proxy for expected profitability, output price. The idea is that firms can manipulate the commodity price by changing their production and hedging policies. This is unlikely given that individual E&P firms are price-takers in global oil and gas markets. Nevertheless, we alleviate the concern regarding the exogeneity assumption of commodity price by employing the Kilian (2009) index as an instrument for commodity price. The Kilian index uses the bulk dry cargo shipping rates to capture global economic activity, and it is a widely used proxy for the aggregate demand for commodities in the literature on the determinants of the oil price. Since an individual oil and gas producer is unlikely to affect the aggregate demand, this index is a valid instrument for the output price. We present 2SLS results in Table 7 where the output price is instrumented by the Kilian index in all columns. In Column (1), we use liquidity measure; in Column (2) we replace liquidity with the unrealized hedging gains; and in Column (3), we add an additional instrumental variable, unrealized hedging gains, to instrument liquidity. Across all cases, the 2SLS coefficients on the price are positive and significant, with the magnitude of these coefficients similar to that in corresponding specifications in Table 4 where the output price is used directly. In all specifications, the F-statistic is above ten, alleviating the weak instrument concern.

Fourth, another potential concern is that lagged hedge ratio may be driving both liquidity and the current hedge ratio. This concern is relevant when the output price has a strong trend in a sample period. For example, if oil price falls (rises) constantly in a sample period, then the lagged hedge ratio would be positively (negatively) correlated with unrealized hedging gains. At the same time, the hedge ratio is possibly autocorrelated. Such concerns can only be addressed using a data set with a long time series. In our sample, oil and gas prices experience both bullish and bearish periods. As we discuss in Subsection 2.2, the average hedging gains for oil and gas producers are close to zero. Therefore, it is unlikely that the serial correlation in hedge ratio drives our results. Nevertheless, we directly address this concern by including lagged hedge ratio as a control variable in Appendix Table X2. We find that the relation between hedge ratio and liquidity (output price) remains positive and significant. Overall, these robustness checks confirm the positive and significant relations that both liquidity and price have with hedge ratio.

3.4. Procyclical Collateral Capacity (PCC): Reserves and Hedging

Our model uses the PCC to explain the positive relation between hedging and expected profitability. We thus expect this positive relation to be stronger among firms with more procyclical collateral capacity, as stated in H2 (ii). To test this implication, we exploit a unique feature in our setting. Oil and gas producers are required to disclose detailed information about their proved oil and gas reserves, which are their most valuable asset and hence the major source of their collateral capacity. Proved reserves are the estimated quantities of commodities that are commercially recoverable under the current economic condition. Proved reserves can be further split into two types of reserves: proved developed and proved undeveloped reserves. Proved developed reserves are the subset that can be readily extracted, while proved undeveloped reserves require additional capital expenditure to extract.[20] Under the U.S. accounting system and Securities and Exchange Commission (SEC) regulation, firms need to revalue the economic producibility of their reserves periodically.[21] Since undeveloped reserves require higher costs to be extracted than developed reserves, the former is usually the first to be written down when the commodity price is low. Thus we expect the value of undeveloped reserves to be more sensitive to the commodity price than developed reserves.

Exploiting this unique setting, we examine whether the positive hedging to price relation

[20] See Society of Petroleum Engineers (https://www.spe.org/en/industry/reserves/) for more detailed definitions of different kinds of reserves.

[21] For example, in the "ceiling test", a firm evaluates the value of its reserves by computing the expected net present value it can generate in the following 10 years, taking into account the expected commodity prices and the expected operating expenses. If the accounting value of the reserves exceeds this "ceiling value", the excess amount must be written down.

is stronger for firms with relatively more proved undeveloped reserves. To test this prediction, we first verify empirically that proved undeveloped reserves are indeed more procyclical than proved developed reserves. We regress the ratio of proved undeveloped reserves to total proved reserves (henceforth PUD ratio) on prices as follows,

$$\text{PUD Ratio}_{it} = \alpha + \beta \text{Output Price}_t + \theta \text{Controls}_{it} + \gamma_i + \varepsilon_{it}\,. \tag{18}$$

In Columns (1)-(3) of Table 9, we use the PUD Ratio_{it} for oil reserves, gas reserves, and the sum of oil and gas reserves in three separate regression specifications (henceforth, oil, gas, and total PUD Ratio, respectively).[22] We include both the oil price and the gas price as the Output Price_t regressors in all three specifications. Since our interest in this analysis is the effect of commodity price on reserves, we control for cash flows from operating and investing activities because production (investment) reduces (increases) the reserve. We include firm-CEO fixed effects to control for time-invariant differences. Standard errors are clustered at the firm and year levels.

In Column (1), we find that the relationship between the oil PUD ratio and the oil price is positive and significant at the 1% level, whereas there is no significant relationship between the oil PUD ratio and the natural gas price. Column (2) finds no significant relationship between the gas PUD ratio and the natural gas price, but a positive and significant relationship between the gas PUD ratio and the oil price. This result is unsurprising because the reserves developed by E&P firms typically produce both oil and natural gas and oil has a much higher price per thermal unit than gas in our sample period. Thus, the economic producibility of reserves often depend more heavily on the price of oil.[23] In Column (3), we

[22]For the specification with oil (gas) reserves, we only use those firms with at least 25% of their production, in thermal units, from oil (gas) in that year. Results are robust to alternate thresholds for oil (gas) producers.

[23]Consistent with this explanation, when we restrict our sample to the small set of firms that get over 90% of their revenue from natural gas production, we find a positive relation between their gas PUD ratio and the natural gas price.

use the total PUD ratio as the dependent variable. Consistent with results in the previous columns, we find that the total PUD ratio is positively and significantly correlated with the oil price and insignificantly related to the gas price. These results provide strong evidence for the idea that the value of proved undeveloped reserves is more sensitive to oil price than that of proved developed reserves.

We proceed to test our model prediction that the positive hedging to price relation should be stronger for firms with relatively more undeveloped reserves. To test this prediction, we run the following regression and report its results in Column (4) of Table 9:

$$\begin{aligned}\text{Hedge Ratio}_{i,t+1} = &\alpha + \beta_0 \text{Price}_t + \beta_1 \text{PUD Ratio}_{it} + \beta_2 \text{Output Price}_t \times \text{PUD Ratio}_{it} \\ &+ \theta \text{Controls}_{it} + \gamma_i + \varepsilon_{it} \,. \end{aligned} \tag{19}$$

The dependent variable is the firm-level hedge ratio. The independent variables include the total PUD ratio, both oil and gas prices, and most importantly the interaction terms of the total PUD ratio and the two prices. Cash flows from operating and investing activities serve as controls. In Column (4) of Table 9, we find that the regression coefficient on the interaction term of oil price and total PUD ratio is positive and statistically significant at the 5% level. Combined with results in Columns (1)-(3) that the value of proved undeveloped reserves is more sensitive to oil price than that of proved developed reserves, our results support the model prediction that the hedging-to-price relation is more positive for firms with relatively more undeveloped reserves. As a placebo test, we find that the regression coefficient on the interaction term of gas price and total PUD ratio is insignificant. This insignificant coefficient is anticipated given that the results in Columns (1)-(3) indicate no significant difference between proved developed and undeveloped reserves' sensitivities to natural gas price. Overall, these results support the model prediction that the more procyclical the collateral capacity is, the more positive is the hedging-to-price relation.

3.5. *The Effect of Liquidity on Production under VCU*

Our Hypothesis H3 predicts that given expected profitability, capital utilization rate is negatively correlated with liquidity. To test this model prediction, we use a version of our base regression model (17) with the utilization rate as the dependent variable:

$$\text{Utilization Rate}_{i,t+1} = \alpha + \beta_1 \text{Liquidity}_{it} + \delta_t + \gamma_i + \varepsilon_{it}\,. \tag{20}$$

Specifically, the dependent variable, Utilization $\text{Rate}_{i,t+1}$, is the ratio of the total production in year *t+1* scaled by the total proved reserves at the end of year *t*. Our empirical measure for liquidity remains the net cash plus unrealized hedging gains scaled by total assets. We continue to use unrealized hedging gains as an instrument for liquidity. We incorporate year fixed effects, δ_t, to control for all common effects, including the effect of expected profitability. Firm-CEO fixed effects, γ_i, account for both time-invariant firm characteristics as well as managerial skill and preferences. The standard errors are clustered at both the year and firm levels.

Column (1) of Table 10 present the results from regressing the utilization rate on liquidity controlling for year and firm-CEO fixed effects. We find that the coefficient on liquidity is negative, but statistically insignificant at conventional levels. Column (2) presents the results from a reduced form model in which unrealized hedging gains is used in place of liquidity. The coefficient estimate on unrealized hedging gains is negative and significant at the 5% level.

Next, we conduct a 2SLS analysis. In Column (3) of Table 10, we present the first stage estimation results from an OLS regression with liquidity as the dependent variable and unrealized hedging gains as an independent variable. The coefficient on unrealized hedging gains is positive and significant at the 1% level. The F-statistic of 27 suggests the instrument is not weak (Staiger and Stock (1997)). In Column (4), we present the 2SLS results where liquidity is instrumented by unrealized hedging gains. The coefficient on the instrumented liquidity is negative and statistically significant at the 5% level. Based on the summary statistics from Table 3, we calculate that a one standard deviation decrease in liquidity of 0.267 leads to an increase in next year production of 1.5% of current reserves. This is a substantial magnitude given that the median next year production is 8.7% of current reserves. Therefore, our 2SLS results support H3 that the intertemporal tradeoff generated by the VCU mechanism induces a negative utilization-liquidity relation.

4. Conclusion

We build a tractable risk management model that incorporates VCU and PCC to study how firm liquidity and expected profitability affect the extent of corporate risk management. Through the VCU feature, our model captures how endogenous capital utilization and production decisions interact with firms' investment, financing, and hedging decisions in the presence of financial frictions, thus further extending the unified risk management model in Bolton et al. (2011). Furthermore, motivated by the important role of the collateral constraint (Rampini and Viswanathan (2010, 2013)), we use the PCC feature to capture the positive correlation between the collateral capacity and the expected profitability. We demonstrate that these two new features lead to novel predictions on how firms manage their cash flow risk based on their liquidity position and expected profitability.

To test these predictions, we manually collect a comprehensive data set of hedging and capital utilization for independent oil and gas E&P firms. Using the output price as a proxy for expected profitability and the unrealized gains on pre-existing hedging positions to identify exogenous shocks to firm liquidity, we find that hedging is positively correlated with liquidity and expected profitability, whereas capital utilization is negatively correlated with liquidity. Our model not only explains the positive relation between liquidity and hedging like the existing theories but also explains the positive hedging-expected profitability relation and the negative utilization-liquidity relation, both of which are challenging to explain with the existing theories. Therefore, our theoretical and empirical results highlight the important roles of VCU and PCC in explaining firms' risk management decisions.

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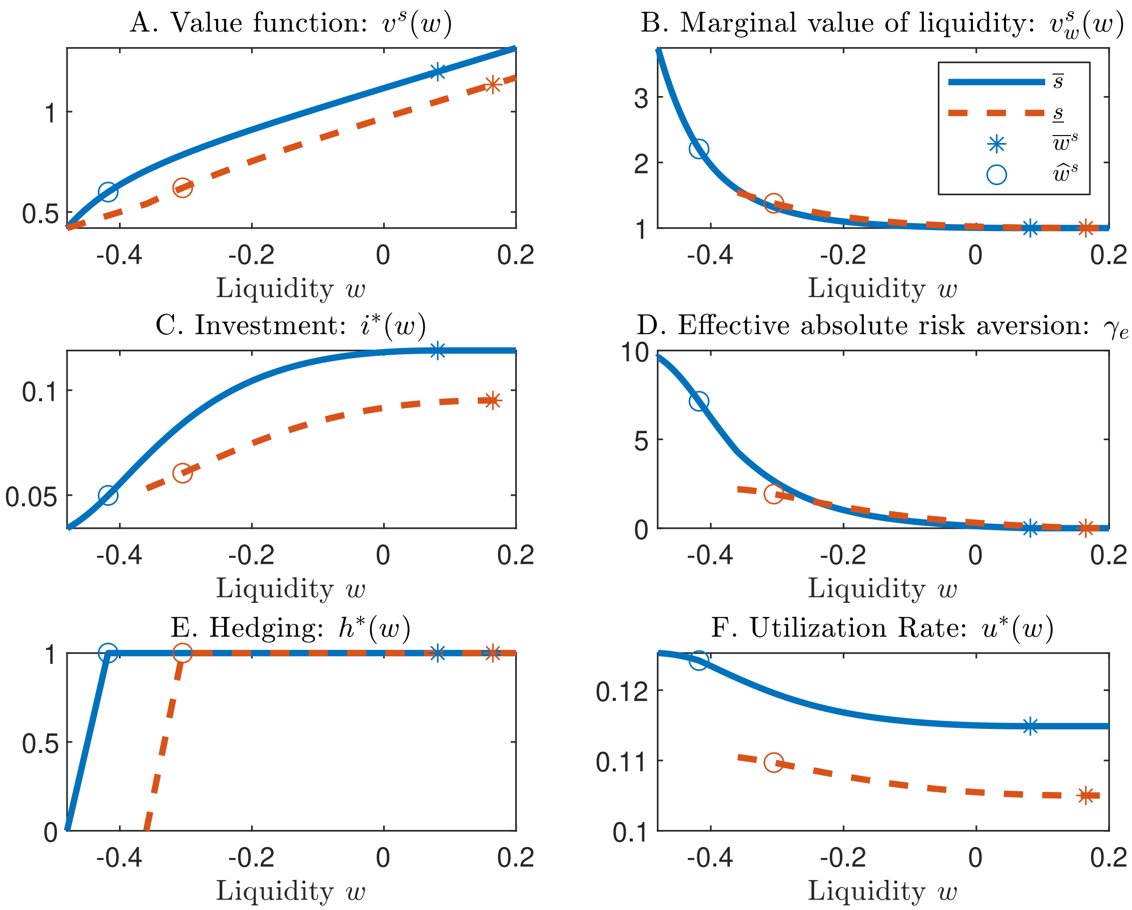

Figure 1: Model Solutions.
The blue solid curves are the policies in the high profitability state $s = \overline{s}$; the red dashed curves are the policies in the low profitability states $s = \underline{s}$. The payout boundaries are $\overline{w}^{\overline{s}} = 0.0814$ and $\overline{w}^{\underline{s}} = 0.1650$. The boundaries of binding collateral constraints are $\hat{w}^{\overline{s}} = -0.4177$ and $\hat{w}^{\underline{s}} = -0.3049$, below which the collateral constraints are binding. Parameter values are calibrated and discussed in Appendix B.

Figure 2: Time Series of Hedge Ratio and Commodity Prices
This figure plots the average fraction of current-year oil (natural gas) production hedged and the average oil (natural gas) price for each year in our sample in the top (bottom) panel. The sample period is 2002 to 2016.

Table 1: Definition of Model Variables and Parameters

This table lists the definitions of the key variables with their units and parameters used in Section 1. In Panel (a), variables scaled by the level of capital K are denoted as the corresponding lower cases in the parentheses. In Panel (b), we report the parameter values used in solving the model. See Appendix B for details on the calibration.

A. Variables

Symbol	Definition
s	$s \in \{\overline{s}, \underline{s}\}$, output price states
K	Level of capital stock
W (w)	Liquidity (scaled liquidity)
V (v)	Value function (scaled value function)
Y	Cumulative operating cash flows
u	Utilization rate of capital
I (i)	Investment in capital (investment rate)
H (h)	Hedging position (hedge to production ratio)
F (f)	Payout to shareholders
γ_e	Effective absolute risk aversion
$\overline{w}^s$	Payout boundary in state s
$\underline{w}^s$	Liquidation boundary in state s
$\hat{w}^s$	Binding collateral constraint boundary in state s

B. Parameters

Symbol	Definition	Value
r	Risk-free rate	4%
r_w	Interest rate on cash savings and borrowings	3%
λ^s	Transition intensity in state s	[0.2,0.2]
u_0	Benchmark utilization rate	0.1
i_0	Benchmark investment rate	0.1
ϕ_i	Investment adjustment cost parameter	6.2
ϕ_u	Utilization adjustment cost parameter	45.9
δ_0	Depreciation to utilization rate	1
μ^s	Expected profitability in state s	[1.8,1.2]
σ_m	Market volatility	0.20
σ_f	Firm-level idiosyncratic volatility	0.13
θ^s	Collateral capacity in state s	[0.48,0.36]
π	Margin requirement	0.5
l	Liquidation value of capital	0.9

Table 2: Variable Definitions

This table defines the key variables used in the analysis and describes how they are constructed from data in financial statements. *Italicized* words in brackets are the corresponding variables in Compustat.

Variable	Definition
Hedge Ratio	The ratio of the next-year hedging volume reported at the end of fiscal year t to the year t production.
Utilization Rate	The next year production volume scaled by fiscal-year end total proved reserves.
Reserves	The fiscal-year end total proved reserves.
Size	Log of the book value of assets (*at*).
Cash Ratio	Ratio of cash and short-term investments (*che*) to the book value of assets.
Book Leverage	Ratio of the sum of long-term debt and debt in current liabilities (*dltt+dlc*) to the book value of assets.
Return on Assets	Ratio of net income (*ni*) to the book value of assets.
Unrealized G/L on Hedging	Sum of unrealized gain/loss on cash flow hedges from accumulated other comprehensive income in shareholders' equity and unrealized gain/loss on non-cash flow hedges from income statement. Collected from the 10-K filings.
Liquidity	Calculated as cash and short-term investments (*che*) - long-term debt (*dltt*) - debt in current liabilities (*dlc*) + unrealized G/L on hedging. This is scaled by the book value of assets.
Net Worth	The ratio of shareholder equity (*seq*) to the book value of assets.
Revision in Reserves	Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage, according to the definition from EIA.
Altman's Z-Score	The formula is 1.2×(working capital / total assets) + 1.4×(retained earnings / total assets) + 3.3×(earnings before interest and tax / total assets) + 0.6×(market value of equity / total liabilities) + 1.0×(sales / total assets). In the terms of Compustat items, it is $1.2 \times \frac{act-lct}{at} + 1.4 \times \frac{re}{at} + 3.3 \times \frac{ebit}{at} + 0.6 \times \frac{csho \times prcc\_f}{at} + 0.999 \times \frac{sale}{at}$
PUD Ratio	The ratio of the proved undeveloped reserves to the total proved reserves.
Output Price	The logarithm of the fraction of total production from oil multiplied by the end-of-period oil futures price plus the fraction of total production from natural gas multiplied by the end-of-period gas futures price.

Table 3: Summary Statistics

This table presents the summary statistics of the key variables. Variable definitions are in Table 2. The sample period is 2002 to 2016.

	N	Mean	SD	P5	P25	P50	P75	P95
Hedge Ratio	851	0.456	0.319	0.000	0.220	0.452	0.659	0.932
Utilization Rate	815	0.104	0.071	0.041	0.067	0.087	0.121	0.209
Book Value of Assets ($ mm)	851	5601.73	9960.64	183.08	588.37	1868.52	5649.38	28634.65
Cash Ratio	851	0.051	0.083	0.000	0.004	0.018	0.060	0.230
Book Leverage	851	0.349	0.237	0.027	0.214	0.312	0.431	0.796
Liquidity	851	-0.300	0.267	-0.787	-0.414	-0.278	-0.154	0.096
Net Worth	851	0.399	0.248	-0.022	0.320	0.429	0.526	0.751
Return on Assets	851	-0.042	0.239	-0.489	-0.049	0.024	0.064	0.135
Unrealized G/L on Hedging	849	-0.004	0.045	-0.084	-0.015	-0.001	0.011	0.067
Oil PUD Ratio	791	0.401	0.205	0.042	0.262	0.411	0.538	0.732
Gas PUD Ratio	791	0.379	0.176	0.079	0.262	0.366	0.504	0.671
Total PUD Ratio	846	0.400	0.170	0.151	0.277	0.389	0.513	0.683
Log Oil Price	851	-0.502	0.398	-1.165	-0.834	-0.494	-0.085	-0.012
Log Gas Price	851	-3.065	0.397	-3.756	-3.396	-3.039	-2.782	-2.187
Output Price	851	-0.922	0.414	-1.614	-1.186	-0.961	-0.630	-0.194

Table 4: Hedging, Liquidity, and Price

This table reports results from regressing hedge ratio on liquidity and output price. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Liquidity.* Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging.* Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is *Hedge Ratio.* The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). The log of the production-weighted commodity price and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		Liquidity	Hedge Ratio
	(1)	(2)	(3)	(4)
Liquidity	0.106			0.342***
	(0.073)			(0.113)
Unrealized G/L on Hedging		0.644**	1.882***	
		(0.237)	(0.289)	
Output Price	0.170***	0.202***	0.226***	0.124**
	(0.055)	(0.063)	(0.048)	(0.048)
Constant	0.645***	0.644***	-0.083*	
	(0.061)	(0.058)	(0.043)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	811	811	811	811
Adj.R^2	0.624	0.629	0.604	
F-Stat for Weak ID Test				42.298

Table 5: Hedging, Net Worth, and Price

This table reports results from regressing hedge ratio on net worth and output price. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Net Worth*. Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging*. Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is *Hedge Ratio.* The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). The log of the production-weighted commodity price and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		Net Worth	Hedge Ratio
	(1)	(2)	(3)	(4)
Net Worth	0.145*			0.656**
	(0.070)			(0.240)
Unrealized G/L on Hedging		0.644**	0.983**	
		(0.237)	(0.358)	
Output Price	0.164**	0.202***	0.198***	0.072
	(0.057)	(0.063)	(0.065)	(0.052)
Constant	0.549***	0.644***	0.591***	
	(0.062)	(0.058)	(0.056)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	811	811	811	811
Adj. R^2	0.627	0.629	0.484	
F-Stat for Weak ID Test				7.539

Table 6: Hedging, Liquidity, and Price for Shale Firms

This table reports results from regressing hedge ratio on liquidity and output price for a subsample of shale producers. We identify shale producers in each firm-year by checking whether the firm's 10-K statement for that year mentions production in at least one of the following major shale play areas: Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, the Permian Basin, and Utica. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Liquidity*. Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging*. Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is *Hedge Ratio*. The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). The log of the production-weighted commodity price and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		Liquidity	Hedge Ratio
	(1)	(2)	(3)	(4)
Liquidity	0.065			0.328**
	(0.071)			(0.118)
Unrealized G/L on Hedging		0.631**	1.922***	
		(0.257)	(0.255)	
Output Price	0.201***	0.226***	0.233***	0.149***
	(0.058)	(0.059)	(0.045)	(0.049)
Constant	0.694***	0.700***	-0.078*	
	(0.061)	(0.057)	(0.043)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	608	608	608	608
Adj. R^2	0.650	0.657	0.613	
F-Stat for Weak ID Test				56.718

Table 7: Instrumenting Output Price

This table reports results from regressing hedge ratio on liquidity and output price. All three columns report the 2SLS results in which the log of the production-weighted commodity price is instrumented with the Killian index. In Column (1), we only instrument the price with the Killian index while including the potentially endogenous *Liquidity*. In Column (2), we replace *Liquidity* with *Unrealized G/L on Hedging*. In Column (3), we simultaneously instrument the price and *Liquidity* with the Killian index and *Unrealized G/L on Hedging,* respectively. The F-statistic for the instrument(s), serving as the test statistic for weak instrument, in the first stage is shown at the bottom of each column. Firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		
	(1)	(2)	(3)
Log Prod Wtd Price	0.206***	0.240***	0.241**
	(0.068)	(0.067)	(0.086)
Liquidity	0.043		0.850**
	(0.073)		(0.384)
Unrealized G/L on Hedging		0.639**	
		(0.264)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO
Observations	761	761	761
F-Stat for Weak ID Test	14.916	12.486	11.493

Table 8: Robustness: Risk-Shifting

This table reports results from regressing hedge ratio on liquidity and output price, where the observations with the bottom 10% of Altman's Z-Score are excluded in each year. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Liquidity.* Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging.* Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is *Hedge Ratio.* The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). The log of the production-weighted commodity price and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		Liquidity	Hedge Ratio
	(1)	(2)	(3)	(4)
Liquidity	0.097			0.362**
	(0.100)			(0.143)
Unrealized G/L on Hedging		0.604**	1.668***	
		(0.251)	(0.234)	
Output Price	0.176**	0.203**	0.192***	0.134**
	(0.060)	(0.070)	(0.044)	(0.052)
Constant	0.649***	0.649***	-0.085**	
	(0.067)	(0.064)	(0.040)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	723	723	723	723
Adj.R^2	0.642	0.646	0.614	
F-Stat for Weak ID Test				50.806

Table 9: Hedging-Price Sensitivity and Procyclical Collateral Value

This table reports results on the relationship between hedging, price, and procyclical collateral. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

Columns (1) - (3) of this table report results of the following OLS regression for oil, gas, and total reserves, respectively:

$$\text{PUD Ratio}_{it} = \alpha + \beta \text{Output Price}_t + \theta \text{Controls}_{it} + \gamma_i + \varepsilon_{it} \, .$$

Column (4) reports results of the following OLS regression for the total hedge ratio:

$$\begin{aligned}\text{Hedge Ratio}_{i,t+1} =& \alpha + \beta_0 \text{Price}_t + \beta_1 \text{PUD Ratio}_{it} + \beta_2 \text{Output Price}_t \times \text{PUD Ratio}_{it} \\ &+ \theta \text{Controls}_{it} + \gamma_i + \varepsilon_{it}\end{aligned}$$

The control variables are cash flows from investing and operating activities. Firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively.

	PUD Ratio			Hedge Ratio
	Oil	Gas	Total	Total
	(1)	(2)	(3)	(4)
Log Oil Price	0.088***	0.086***	0.075***	-0.081
	(0.020)	(0.023)	(0.017)	(0.082)
Log Gas Price	-0.008	-0.004	-0.025	0.172
	(0.027)	(0.021)	(0.018)	(0.108)
PUD Ratio				-0.458
				(0.559)
Log Oil Price × PUD Ratio				0.428**
				(0.195)
Log Gas Price × PUD Ratio				-0.219
				(0.194)
Constant	0.482***	0.415***	0.396***	0.980***
	(0.082)	(0.061)	(0.056)	(0.318)
Controls	Y	Y	Y	Y
Fixed Effect	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	448	586	755	755
Adj.R^2	0.656	0.610	0.656	0.633

Table 10: Utilization Rate and Liquidity

This table reports results from regressing capital utilization rate on liquidity. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Liquidity.* Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging.* Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is the ratio of the following year's total production scaled by current year reserves (*Utilization Rate).* The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). Year and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Utilization Rate		Liquidity	Utilization Rate
	(1)	(2)	(3)	(4)
Liquidity	-0.015			-0.056**
	(0.015)			(0.021)
Unrealized G/L on Hedging		-0.110**	1.967***	
		(0.047)	(0.360)	
Constant	0.099***	0.103***	-0.289***	
	(0.004)	(0.000)	(0.001)	
Firm-CEO FE	Y	Y	Y	Y
Year FE	Y	Y	Y	Y
Observations	779	779	811	779
Adj.R^2	0.557	0.558	0.617	
F-Stat for Weak ID Test				26.508

Appendix

A. An Example of Oil/Gas Reserve Dynamics

Production, capital utilization, and capital depreciation. We provide a real world example of reserve changes in the following table, using the 2006 10-K filing of Chesapeake Energy Corporation. The example illustrates the various components of changes in reserves and that production directly depletes reserves. This table presents the summary of changes in estimated reserves of Chesapeake for the fiscal year 2006. Its original 10-K filings are available here. Here, mbbl is one thousand barrels of crude oil; mmcf is one million cubic feet of natural gas; mmcfe measures the total energy measured in mmcf equivalent, where one mbbl of oil is considered equivalent to six mmcf of gas.

	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
December 31, 2006			
Proved reserves, beginning of period	103,323	6,900,754	7,520,690
Extensions, discoveries and other additions	8,456	777,858	828,594
Revisions of previous estimates	(3,822)	539,606	516,676
Production	(8,654)	(526,459)	(578,383)
Sale of reserves-in-place	(3)	(123)	(141)
Purchase of reserves-in-place	6,730	627,798	668,178
Proved reserves, end of period	106,030	8,319,434	8,955,614
Proved developed reserves:			
Beginning of period	76,238	4,442,270	4,899,694
End of period	76,705	5,113,211	5,573,441

Assets impairment. In the same 10-K filing, Chesapeake discusses how commodity prices can affect the estimated reserves, "The volatility of oil and natural gas prices and the impact of revisions to reserve estimates can have a significant impact on the company's financial condition and results of operations. Our oil and gas depreciation, depletion and amortization rates have increased from $1.38 per mcfe in 2003 to $1.91 per mcfe in 2005 reflecting the impact of increases in prices and finding costs during these periods. As of December 31, 2005, a decrease in natural gas prices of $0.10 per mcf and a decrease in oil prices of $1.00 per barrel would reduce the company's estimated proved reserves by 3.5 bcfe and by 1.1 bcfe, respectively, as a result of economic truncation of the expected producing lives of some properties."

B. Variables and Parameters of the Model

Table 1 summarize the key variables used in the model and presents our calibration of the parameters. As we have already discussed the variable definitions in Section 1, we focus on Panel B and discuss our calibration below.

The risk-free rate is 4%, the average one-year treasury rate in the U.S. The interest rate on savings and borrowings r_w is set to be 3%, which is equivalent to assuming an average corporate tax rate of 25%. The transition intensity λ^s is set to be 0.2, which generates an annual autocorrelation of 0.6 for the expected profitability, to match the annual autocorrelation of the oil price in data.

The benchmark utilization rate u_0 is 0.10, which is the mean production to proved reserves ratio in our sample. The benchmark investment rate i_0 is set to be the same as u_0, so that in the benchmark case, the capital stock has zero growth. The investment cost parameter ϕ_i is 6.2, which is the estimated value for oil and gas firms in Warusawitharana and Whited (2015). The production cost parameter ϕ_u is 45.9, which is 7.3 times of the investment cost parameter because we want to match the fact that the standard deviation of investment is 7.3 times that of production in our sample. Finally, the depreciation to utilization rate δ_0 is 1, matching the fact that one unit of production depletes one unit of proved reserves of oil and gas producers.

We motivate the expected profitability μ^s from data. To be specific, we divide our sample into high and low oil price subsamples by the median oil price. The EBITDA return on assets is 0.18 and 0.12 in these two subsamples, respectively. We then divide these numbers by the benchmark utilization rate u_0 and obtain the parameter values 1.8 and 1.2, respectively. The market volatility σ_m is set to the unconditional volatility of the EBITDA return on assets, 0.20. The firm-level idiosyncratic volatility σ_f is 0.13, which is the square root of the difference between the sample variance of ROA (0.24^2) and σ_m^2.

The collateral capacities θ^s are set to 0.48 and 0.36 in the high and low profitability states, respectively. This is within the range of the collateral capacity estimations of 0.36-0.49 in Li et al. (2016). The margin requirement π is 0.5. Finally, the liquidation value of capital l is 0.9, following Bolton et al. (2011).

C. Details of Model Proof and Solutions

Proof of monotonicity of value function $v^s(w)$ When the firm is inside the payout and liquidation boundaries, consider the marginal value of $v^s(w)$. Suppose the firm has a small amount of additional liquidity, which is $\triangle w$. Because the firm has the option to payout, it can always choose to pay out $\triangle w$ to the shareholders, in which the firm value is $v^s(w) + \triangle w$ to the shareholders. Therefore, the firm value is at least $v^s(w) + \triangle w$, i.e., $v^s(w + \triangle w) \geq v^s(w) + \triangle w$. So the value function is increasing in liquidity w and the marginal value is at least 1. The marginal value is 1 when the firm weakly prefers paying out additional dollars to saving them inside the firm.

First-order conditions and optimal policies The first-order conditions of the problem (8) are

$$
\begin{aligned}
[i]: &\quad v^s = [w + 1 + \phi_i (i - i_0)]\, v^s_w \\
[u]: &\quad \delta_0 v^s = (\delta_0 w + \mu^s + \phi_u (u - u_0))\, v^s_w + \sigma_m^2 (1-h)^2 u v^s_{ww} \\
[h]: &\quad 0 = \sigma_m^2 (1-h)\, u^2 v^s_{ww} \text{ if unconstrained.}
\end{aligned}
$$

Rearranging them and applying the collateral constraint, we can obtain the optimal policies.

We can also derive $\hat{w}^s$, which is given implicitly by $1 = \frac{\theta^s + \hat{w}^s}{\pi u^*(\hat{w}^s, s)}$, or

$$
1 = \frac{(\theta^s + \hat{w}^s)\left(\phi_u - \sigma_f^2 \frac{v^s_{ww}}{v^s_w}\right)}{\pi\left[(\delta_0 w + \mu^s + \phi_u u_0) - \delta_0 \frac{v^s}{v^s_w}\right]}.
$$

Model solutions with high market risk volatility Figure X1 presents the solutions of optimal hedging and utilization rate when the market risk volatility σ_m is twice of the benchmark calibrated value, i.e., $\sigma_m = 0.4$. All other parameters are kept the same as the calibration in Table 1. The main message here is that, when market risk volatility is high, the risk-return tradeoff can dominate the intertemporal tradeoff when hedging is constrained by the collateral capacity. As a result, the utilization rate in Panel B of Figure X1 is increasing with liquidity when liquidity is lower than $\hat{w}^{\overline{s}}$.

D. Data Appendix

D.1. Sample Construction

We identify independent oil and natural gas producers in the following steps. First, we identify domestic common stocks in the CRSP/Compustat universe that (1) have a Global Industry Classification Standard (GICS) code of 10102010 (Integrated Oil & Gas) or 10102020 (Oil & Gas Exploration & Production) or (2) have a missing GICS code but a Standard Industrial Classification (SIC) code of 1311 (Crude Petroleum and Natural Gas) during our sample period.[24] We then exclude firms with a significant refinery or downstream business by excluding those that are associated with the following GICS codes for at least one year during our sample period: 10102010 (Integrated Oil & Gas), 10102050 (Coal & Consumable Fuels), 55105010 (Independent Power Producers), or 10101020 (Natural gas distribution). If the GICS code is missing for all years, we require the firm to have a SIC code 1311 for the whole sample period. After these steps, we are left with 184 unique GVKEYs. Finally, we exclude microcap stocks by removing firms whose book value of total assets never exceeds $300 million during the sample period. To facilitate cross-firm comparison, we keep only firms with a fiscal year ending in December. This procedure identifies 116 unique GVKEYs, for which we then manually collect hedging data. After excluding a few firms that report derivative positions in a format substantially different from the other firms, our sample includes 112 unique GVKEYs, and 947 firm-year observations of the independent oil and gas producers.

To extract hedging data of the oil and gas producers, we write a Python program to identify and scrape tables in 10-K filings that report their hedging activities. We then manually go through all these tables and extract their contract-level details: derivative instrument types (put/call/collar options, swaps, futures/forward, and other contracts), notional volumes, maturities, strike prices (if available), and underlying commodity types (oil, gas and various liquefied gas). We aggregate the volumes of all contracts that protect the downside price risk of future production for each firm-year to arrive at the hedging position. These contracts include forward, futures, swap, options, and fixed-price physical delivery contracts.

[24] We use GICS in priority relative to SIC because cross-checking with Bloomberg reveals that using GICS is more reliable than using SIC. The SIC identification approach misses some large oil and gas producers, such as EQT, SWN, and UNT. Our approach identifies 207 unique GVKEYs within our sample period.

The fixed-price physical delivery contracts are conceptually similar to the purchase obligations studied in Almeida, Hankins, and Williams (2019), although the former is for output price hedging and the latter is for input price hedging. Since the derivative markets for the crude oil are well developed, the usage of fixed-price physical delivery contracts is quantitatively small in our sample. Our results are not sensitive to excluding these contracts. Call options are excluded in our analysis as they do not pertain to downside risk management. Finally, we compute hedge ratio as the ratio of the hedging volume for the next fiscal year over the production volume of the current fiscal year. We prefer to use the production volume reported in the same 10-K filing to scale the hedging volume because mergers and acquisitions and divestiture often make the hedging and production reported in different 10-K filings incomparable. In Appendix D.2, we provide a detailed example of how we construct the hedging volume.

We drop the observations whose hedging information we are unable to identify, leaving us with 876 observations. We further exclude observations that cannot be matched to Compustat, that are non-U.S. based firms, and that do not have production data. Our final sample consists of 851 firm-year observations.

D.2. Construction of Hedge Ratio: An Example

APACHE CORPORATION AND SUBSIDIARIES

Form 10-K for the fiscal year ended December 31, 2009 (link)

Commodity Derivative Instruments

As of December 31, 2009, Apache had the following open crude oil derivative positions:

(W.A. = weighted average. Bbl is barrel of oil; BOE denotes barrel of oil equivalent; BTU is British thermal unit; CF represents cubic feet; GJ is Gigajoule. "M" is one thousand and "MM" is one million.)

	Fixed-Price Swaps		Collars		
Production Period	Mbbls	W.A. Fixed Price	Mbbls	W.A. Floor Price	W.A. Ceiling Price
2010	2,383	$68.71	10,396	$65.01	$80.84
2011	3,650	70.12	6,202	66.24	87.04
2012	3,292	70.99	2,554	66.07	89.13
2013	1,451	72.01			
2014	76	74.50			

As of December 31, 2009, Apache had the following open natural gas derivative positions:

	Fixed-Price Swaps			Collars			
Production Period	MMBtu (in 000's)	GJ (in 000's)	W.A. Fixed Price	MMBtu (in 000's)	GJ (in 000's)	W.A. Floor Price	W.A. Ceiling Price
2010	82,125		$5.81	30,550		$5.48	$7.07
2010		54,750	5.37				
2011	10,038		6.61	9,125		5.00	8.85
2011		23,725	6.75		3,650	6.50	7.10
2012	2,745		6.73	10,980		5.75	8.43
2012		29,280	6.95		7,320	6.50	7.27
2013	1,825		7.05				
2014	755		7.23				

Defining hedging position. Furthermore, Apache reported in its FY 2010 10-K filing that "Australia has a local market with a limited number of buyers and sellers resulting in mostly long-term, fixed-price contracts that are periodically adjusted for changes in the local consumer price index." We consider those contracts as fixed-price physical delivery contracts, which are also part of the hedging policies.

We define the hedging positions as follows. First, we define hedging for the next-year production as the short-term hedging and the hedging beyond one year as the long-term hedging. Second, we convert all thermal/volume units to barrel of oil equivalent (BOE) using the following conversion rule.

$$1 \text{ BOE} = 6 \text{ MMBTU} = 6 \text{ MCF} = 6.12 \text{ GJ} = 42 \text{ GAL}.$$

Third, we only count the contracts that protect firms from downside risks of the commodity prices. Therefore, in this example, the short-term oil hedging is 2,383Mbbls + 10,396Mbbls = 12,779 MBOE. The total short-term natural gas hedging is 82,125 MMBtu (in 000's) + 54,750 GJ (in 000's) + 30,550 MMBtu (in 000's) + 72.9 Bcf (Australian gas production) = 39,875 MBOE.

D.3. Realized and Unrealized Hedging Gains

Unlike unrealized hedging gains, realized hedging gains are not a proxy for an unpredictable shock to firms' liquidity. This is because realized hedging gains pertain to derivatives for the current year production, whereas the unrealized gains pertain to derivatives hedging for future production. Since the current year production and its corresponding hedging position have offsetting exposures to the commodity price, the realized hedging gains caused by changes in commodity price over the current year will be offset by the corresponding changes in the revenue of the current year production before hedging, leading to no net effect on firms' liquidity. To put it in another way, the hedged revenue is predetermined when the hedging positions is established in the previous year and thus not affected by the changes in commodity price over the current year.

To give an example, consider a firm that enters into forward contracts at the beginning of 2004 to sell 100 million barrels of crude oil equivalent (MMBOE) of its 2004 oil production and 50 MMBOE of its 2005 oil production. Assume that the forward prices for the 2004 and 2005 contracts are the same at $50 per barrel of oil equivalent (BOE). For simplicity, we further assume that the risk-free rate and the convenience yield are zero. Suppose both the spot and forward prices are $50 per BOE at the beginning of 2004 and both fall to $40 per BOE at the end of 2004. So the realized gains on the 2004 contract and the unrealized gains on the 2005 contract are $1B and $500M, respectively. Three observations are in order. First, the change in spot price during 2004 affect the realized gains/losses on the 2004 forward contract and thus affect the composition of the hedged revenue of 2004 oil production – whether it comes from the realized hedging gains or the unhedged revenue. However, the change in spot price does not affect the hedged revenue for the 100 MMBOE of 2004 oil production, which is $5B regardless of the realized price at the end of 2004 (100 MMBOE times $50 per BOE). Second, the change in forward prices throughout 2004 affects the unrealized gains and losses on the 2005 forward contract, and this $500M unrealized gains in turn affect the firms' liquidity position. Third, if the spot price in 2005 does not change from the spot price at the end of 2004, the unrealized gains of $500M on the 2005 forward contract at the end of 2004 will be reclassified as the realized gains at the end of 2005. Thus, the realized gains and losses may not correlate with the contemporaneous changes in commodity prices.

E. Appendix Figures and Tables

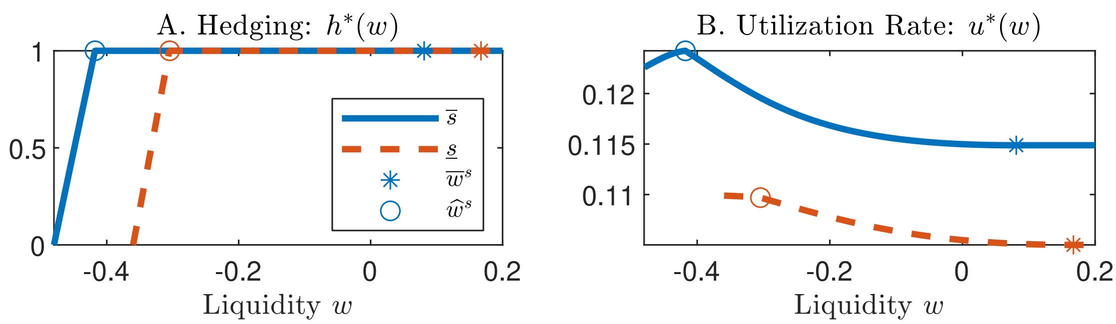

Figure X1: Model Solutions with High Market Risk Volatility
The blue solid curves are the policies in the high profitability state $s = \overline{s}$; the red dashed curves are the policies in the low profitability states $s = \underline{s}$. The payout boundaries are $\overline{w}^{\overline{s}} = 0.0811$ and $\overline{w}^{\underline{s}} = 0.1673$. The boundaries of binding collateral constraints are $\hat{w}^{\overline{s}} = -0.4177$ and $\hat{w}^{\underline{s}} = -0.3046$, below which the collateral constraints are binding. All parameter values are the same as the calibration in Appendix B except the market risk volatility σ_m is now 0.40.

Table X1: Hedging, Net Worth, and Price

This table reports results from regressing hedge ratio on net worth and output price, where we include *Revision in Reserves* as an additional control. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Net Worth*. Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging*. Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is *Hedge Ratio*. The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). The log of the production-weighted commodity price and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		Net Worth	Hedge Ratio
	(1)	(2)	(3)	(4)
Net Worth	0.120			0.666**
	(0.079)			(0.248)
Unrealized G/L on Hedging		0.679**	1.019***	
		(0.236)	(0.325)	
Revision in Reserves	0.036	0.051	0.272***	-0.130
	(0.097)	(0.090)	(0.088)	(0.134)
Output Price	0.196***	0.232***	0.194***	0.103*
	(0.050)	(0.055)	(0.055)	(0.056)
Constant	0.590***	0.674***	0.593***	
	(0.057)	(0.052)	(0.050)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	710	710	710	710
Adj.R^2	0.628	0.633	0.520	
F-Stat for Weak ID Test				9.851

Table X2: Robustness: Including Lagged Hedging

This table reports results from regressing hedge ratio on liquidity and output price, where lagged hedge ratio is included in all regressions. Column (1) presents the coefficient estimates of the OLS specification. Columns (2) to (4) present the coefficient estimates of the instrumental variables specifications in which *Unrealized G/L on Hedging* is used as an instrument for *Liquidity.* Column (2) presents the reduced form relation between *Hedge Ratio* and *Unrealized G/L on Hedging.* Column (3) presents the first stage coefficients, and Column (4) the two-stage least squares estimates where the dependent variable is *Hedge Ratio.* The F-statistic for the instrument in the first stage, serving as the test statistic for weak instrument, is shown at the bottom of Column (4). The log of the production-weighted commodity price and firm-CEO fixed effects are included in all specifications. Standard errors, reported below coefficients in parentheses, are clustered at the firm and year levels. ***, **, and * denote 1%, 5%, and 10% statistical significance, respectively. Observations are at the firm-year level and the sample period is 2002 to 2016. Variable definitions are in Table 2.

	Hedge Ratio		Liquidity	Hedge Ratio
	(1)	(2)	(3)	(4)
Liquidity	0.085			0.321**
	(0.066)			(0.116)
Unrealized G/L on Hedging		0.632**	1.965***	
		(0.244)	(0.306)	
Output Price	0.192***	0.220***	0.219***	0.150***
	(0.052)	(0.056)	(0.050)	(0.048)
Lag Hedge Ratio	0.069	0.057	0.002	0.057
	(0.085)	(0.083)	(0.042)	(0.080)
Constant	0.618***	0.625***	-0.095*	
	(0.065)	(0.063)	(0.053)	
Fixed Effects	Firm-CEO	Firm-CEO	Firm-CEO	Firm-CEO
Observations	713	713	713	713
Adj.R^2	0.617	0.623	0.629	
F-Stat for Weak ID Test				41.228