Cooperate or Compete? Insights from Simulating a Global Oil Market with No Residual Supplier

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ABSTRACT

Structural changes in the oil market, such as the rise of tight oil, are impacting conventional market dynamics and incentives for producers to cooperate. What if OPEC stopped organizing residual production collectively? We develop an equilibrium model to simulate a competitive world oil market from 2020 to 2030. It includes detailed conventional and unconventional oil supplies and financial investment constraints. Our competitive market scenarios indicate that oil prices first decline and tend to recover to reference residual supplier scenario levels by 2030. In a competitive oil market, a reduction in the financial resources made available to the global upstream oil sector leads to increased revenues for low-cost producers such as Saudi Arabia. Compared to the competitive scenario, Saudi Arabia does not benefit from acting alone as a residual supplier, but, under some assumptions, it benefits from being part of a larger group that works collectively as a residual supplier.

Keywords: Competitive Oil Market, Residual Supplier, Tight Oil, OPEC, Saudi Arabia

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1. INTRODUCTION

The oil market is undergoing profound structural changes due to the tight oil revolution and the prospect of plateauing or peaking oil demand. These developments could induce either more co-operation or more competition between oil-producing countries. In this paper, we simulate a global oil market with no residual supplier that would organize production levels to manage the price of oil, i.e., a global market where all producers behave as competitive price takers.

We develop an equilibrium model of the global oil market through 2030 with a detailed representation of oil-producing assets throughout the world. Rather than applying a dominant firm model with a competitive fringe, as is standard in oil modeling (Plaut 1981; Rauscher 1988; Jones 1990; Behar and Ritz 2017; Golombek et al. 2018; Volkmar 2019; Pierru et al. 2018; Pierru et al. 2020), we test cases under a competitive market with no residual supplier scenario in which every oil-producing country behaves as a price taker. In this case, investment and production decisions depend only on how marginal production cost compares to price. We analyze how market prices would potentially materialize in such a scenario.

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We then compare the outcomes of the hypothesized competitive market to an alternative reference residual supplier scenario. We examine two cases within this scenario: in the first, OPEC members collectively operate as a residual supplier; in the second, Saudi Arabia acts as the only residual supplier, and other OPEC members join the competitive fringe. In both instances, the residual supplier follows a price targeting strategy: it adds or subtracts oil from the market to achieve the desired global market price, based upon how much is being supplied by the fringe.[1] We calculate Saudi Arabia's oil revenues in the different scenarios and examine which market configuration is the most profitable for Saudi Arabia. This analysis has implications for Saudi Arabia's potential willingness to fill the role of residual supplier.

The two residual supplier cases reflect different perspectives within the research community. While some studies treat OPEC as the world's dominant oil firm (Rauscher 1988; Jones 1990), others (Plaut 1981; Adelman 1995) argue that Saudi Arabia performs the role of the dominant firm within OPEC when its members fail to coordinate the organization's output. In a review of the evolution of OPEC models, Fattouh and Mahadeva (2013) concluded that OPEC's market power has varied over time and thus that no single model fits OPEC's behavior. Behar and Ritz (2017) suggest that OPEC can shift to a market share strategy in certain circumstances.

Following the oil crisis of the 1970s, the literature on the strategies of oil-producers (especially OPEC) regarding pricing and production decisions has grown substantially (e.g. Powell 1990; Gately 1995). The geopolitical environment and oil market structure are much different today than in the 1980s-90s. First, the market has been transformed by a combination of increasing production and declining costs of unconventional tight oil, weakening OPEC's market dominance and its ability to influence prices. Second, non-OPEC oil supply has grown at a different pace than global oil demand. Third, legislative attempts, such as the No Oil Producing and Exporting Cartels (NOPEC) Act, which was proposed by the United States (U.S.) Congress to allow the national oil companies that make up OPEC to be sued under U.S. antitrust law, may potentially make it difficult for OPEC to engage in coordinated cuts in world oil supply (Rystad Energy 2018b; Reuters 2019).

To our knowledge, the only other study that investigates the implications of a competitive market is by Bornstein et al. (2019) who developed an equilibrium model of the oil industry. The parameters of the model are estimated using micro-level (oil company) data covering the 1970-2015 period. The paper considers two alternative market structures. In the first structure, both OPEC and non-OPEC companies behave competitively, whereas in the second, OPEC companies cooperate, and non-OPEC companies are a competitive fringe. Then using variance decomposition and impulse-response functions, the paper measures the impacts of exogenous demand shocks and supply disruptions on prices, production, and investment. The results show that although demand and supply shocks affect similarly the variance of prices in both market structures, the market structure has a significant impact on steady-state oil prices. Within the same framework, the authors also study the implications of introducing competitive fracking and show that the volatility of oil prices declines with the increase in the share of fracking production in total oil production.

Our paper differs from Bornstein et al. (2019) in several aspects. First, to simulate a world oil market with and without a residual supplier, we take an equilibrium approach based on piecewise linear supply curves, deterministic price patterns, and a demand function calibrated to a reference outlook, whereas Bornstein et al. (2019) focus on demand and supply shocks in alternative market structures. Second, unlike Bornstein et al. (2019) who use historical data for modeling and evalu-

1. We do not examine the conditions under which a transition from the residual supplier case to a competitive market occurs. We leave this question for future research. Note also that our residual supplier scenario is designed to replicate the International Energy Agency's World Energy Outlook projections and not to maximize the profit of the residual supplier.

ation, we design scenarios based on institutional projections. Third, Bornstein et al. (2019) do not consider the availability of capital for investment in the oil industry. We simulate various scenarios taking into account financial constraints and compare the outcomes of alternative market structures. Thus, our simulations enable us to analyze what would happen if investors and financial institutions shift away from the upstream oil sector. Finally, Bornstein et al. (2019) do not look at the implications of market structure for Saudi Arabia while we simulate Saudi Arabia's free cash flows under alternative market assumptions.

The framework we propose and the simulations we perform provide useful insights regarding the implications of a competitive oil market. Hence, we believe that our study contributes to the debates over the future of the global oil market and the significance of the residual supplier role traditionally filled by Saudi Arabia and OPEC.

The next section describes the representation of demand, the decision rules for producers, and other features of the model. Section 3 details scenarios that explore the consequences of structural changes in the world oil market, including the role of the residual supplier, and different scenarios regarding investment in new oil production capacity. Section 4 discusses the results and their interpretation. Finally, Section 5 offers concluding remarks.

2. MODEL DESCRIPTION

We build an aggregate model of the global oil market within an equilibrium framework in which price clears the market. The discussion below describes the supply and demand representations and provides a comparison to techniques used in other world oil market models. Online Appendix A provides the complete mathematical formulation with equations.

The model simulates the medium-term consequences of a market with and without a residual supplier. First, to calibrate our demand outlook, we establish a reference residual supplier scenario in which the residual supplier targets a given oil price by increasing or decreasing production in response to the total output of all other suppliers, treated as fringe competitors. Then we solve for the market equilibrium under the competitive scenarios where all producers behave as price takers (no residual supplier). The model also estimates the financial consequences for different suppliers in terms of oil revenues.

In the model, the world oil market clears, for all periods simultaneously, with demand balancing supply on an annual basis, for all hydrocarbon liquids including crude oil, condensates, natural gas liquids (NGL), refinery gains and other liquids (biofuels and alcohols destined for the same market as petroleum products). We represent global demand and supply as a single node and do not account for regional crude flows.[2]

2. It should be noted that there are several other factors that are not accounted for in our model although they can potentially impact oil market dynamics. To give some examples, the literature on exhaustible resources documents the impact of taxation on the oil industry. For instance, Rao (2018) studied how taxes affected oil produced by wells in California. Smith (2012) developed a model of oil field development and showed how alternative tax instruments and fiscal regimes can impact oil exploration, development, and production. More recently, Brown, Maniloff, and Manning (2020) focused on the U.S. oil industry and showed that drilling is inelastic with respect to changes in severance taxes. Another issue that our framework does not consider is the productivity impact of nationalization (or denationalization) in the oil industry as we do not distinguish between national oil companies (NOCs) and private international oil companies (IOCs). Hartley and Medlock (2008, 2013) reported that NOCs have non-commercial objectives making them more focused on output and cash flow in the short run and less focused on long-run strategies in developing new field resources than IOCs. The recent paper by Gong (2020) presented additional empirical evidence on the relative inefficiency of NOCs. Technical changes affecting both supply and demand sides, time-varying income and price elasticities of oil demand (Baumeister and Peersman, 2013) are some other factors we do not model in this paper. We leave these aspects for future extensions of this work.

2.1 Representation of global oil demand

The following equation (1) specifies total world oil demand in each year t (D_t)

$$D_t = A_t \bar{p}_t^{\varepsilon} Y_t^{\gamma} \tag{1}$$

where A_t is a scaling parameter capturing the effects of all exogenous factors, and $\bar{p}_t$ is the three-year moving average market price. We consider a single global oil price based on the Brent Crude oil marker. Y_t is the current global gross domestic product (GDP), ε is the long-run price elasticity of oil demand, and γ is the long-run income elasticity of oil demand, or the impact of global GDP. The price elasticity of demand is applied to the three-year moving average price to reflect the lag on the impact of oil prices on demand (Hamilton 2003; Kilian 2008).

Global GDP in year t is given by

$$Y_t = Y_{t-1}\left(1 + \tilde{g}_t \left(\bar{p}_t / \tilde{p}_t\right)^{\theta}\right) \tag{2}$$

where $\tilde{g}_t$ is a reference GDP growth rate. The ratio $\bar{p}_t / \tilde{p}_t$ in equation (2) represents the impact of prices on GDP growth, where $\tilde{p}_t$ is the three-year average reference price linked to the reference GDP growth. The parameter θ can be interpreted as the elasticity of real economic growth with respect to variations in the price of oil. For instance, if the moving average oil price $\left(\bar{p}_t\right)$ is higher than that of the reference level $\left(\tilde{p}_t\right)$, then for $\theta < 0$ the economic growth from $t-1$ to t will be slower than the reference $\left(\tilde{g}_t\right)$, and vice versa.[3]

A straightforward way to specify equations (1) and (2) is to use elasticity estimates available in the literature. Then, A_t can be calibrated based on consistent projections from a desired reference case (i.e., using the expected oil demand $\tilde{D}_t$, moving average oil price $\tilde{p}_t$, and global GDP $\tilde{Y}_t$ in the reference scenario). We show in the online Appendix A.4 that an approximate value of θ can be obtained by formulating a time series equation that relates the growth rate of global GDP to that of oil prices.

2.2 Calibrating the world oil demand

We calibrate the demand curve to replicate a reference scenario that projects annual world demand, average oil price and global GDP growth. We consider the period from 2019 to 2030, using the 2019 World Energy Outlook (WEO) from the International Energy Agency (IEA 2019b).

The scaling coefficient A_t from equation (1) is set as follows:

$$A_t = \frac{\tilde{D}_t}{\tilde{p}_t^{\varepsilon} \tilde{Y}_t^{\gamma}} \tag{3}$$

In other words, A_t guarantees that the price and GDP outlook replicate the global oil demand projected in the reference scenario.

$$D_t = \tilde{D}_t \left(\frac{\bar{p}_t}{\tilde{p}_t}\right)^{\varepsilon} \left(\frac{Y_t}{\tilde{Y}_t}\right)^{\gamma} = A_t \bar{p}_t^{\varepsilon} Y_t^{\gamma} \tag{4}$$

Regarding the price and income elasticities of oil demand, the relevant literature offers no consensus. The estimates range widely, from -0.01 to -0.58 for price elasticity (ε) and 0.24 to 1.32 for income elasticity (γ) (Javan and Zahran 2015). For the simulations presented in this paper, we select -0.25 as the long-run price elasticity of oil demand and 0.75 for the long-run income elasticity.

3. James L. Smith suggested this demand side representation and has our gratitude for this.

We also run sensitivity analyses by calibrating the model across ranges of elasticities of price (from -0.1 to -0.5) and income (from 0.25 to 1).

We source world oil prices for the years 2017 and 2018 from Reuters to construct the three-year moving average prices during the first two years of the study period. All prices and values mentioned in this paper are adjusted to 2019 real terms and are in U.S. dollars ($).

The WEO publishes several outlooks for the global oil market. We focus on the organization's Stated Policies Scenario. Under this scenario, annual demand growth slows to an average of 0.8% as global demand rises from 98.8 million barrels per day (MMb/d) in 2019 to 107.7 MMb/d in 2030. This scenario assumes Brent prices steadily increase from $61 per barrel ($/b) in 2019 to $88/b in 2025, and $96/b in 2030. Over this period GDP growth averages 3.6%, and oil demand does not peak. Note that the impact of the coronavirus pandemic on demand is not factored into the 2019 Stated Policies Scenario.

As part of our sensitivity analysis, discussed in Section 4.3, we also calibrate our model to the International Energy Outlook (IEO) of the Energy Information Administration (EIA 2019). The IEO projects weaker average price and demand growth, with Brent hitting a maximum of $76.9/b and global demand reaching 105.8 MMb/d in 2030, reflecting annual growth of 0.5%; GDP also expands more slowly at an average growth rate of 3.3%. Table A.1 in the online Appendix A.4 shows the values from both the WEO and IEO.

2.3 Global oil supply model

The supplier's optimization problem is presented in equation block (5). All indices, variables and parameters are shown in Table 1.

$$
\begin{aligned}
\max \pi = & \sum_t \frac{1}{(1+r)^{(t-t_s)}} \sum_j q_{jt}\left(p_t M_{jt} - C_{jt}\right) \\
& + \sum_{t',t\geq t'} \frac{1}{(1+r)^{(t-t_s)}} \sum_k x_{kt't}\left(p_t M_{kt+\Delta t} - C_{k,t+\Delta t}\right) \\
& + \sum_{k_L} \sum_{t'\geq T_{k_L}} \sum_{\tau=t_N+1}^{\infty} \frac{p_{t_N} M_{k_L\tau+\Delta t} - C_{k_L\tau+\Delta t}}{(1+r)^{(\tau-t_s)}} b_{k_L t'} F_{k_L\tau+\Delta t} \\
& - \sum_{t'} \sum_{\tau=t_s}^{t_\infty} \sum_{k_L} \frac{K_{k_L\tau+\Delta t} b_{k_L t'}}{(1+r)^{(\tau-t_s)}}
\end{aligned}
\tag{5}
$$

$$s.t.\ b_{kt}, q_{jt}, x_{kt't} \geq 0$$

$$E_{jt} \geq q_{jt} \qquad \perp \lambda_{jt} \geq 0 \qquad \forall\, jt \tag{5.1}$$

$$\left(b_{kt'} F_{kt+\Delta t}\right) \geq x_{kt't} \qquad \perp \mu_{kt't} \geq 0 \qquad \forall\, k, T_k \leq t' \leq t \tag{5.2}$$

$$\sum_{t'k\ \forall\, T_k \leq t'} b_{kt'} \leq 1 \qquad \perp \gamma_k \geq 0 \qquad \forall\, k \tag{5.3}$$

$$\hat{\mathrm{H}}_{t'} \geq \sum_{k_S} K_{k_S t'+\Delta t} b_{k_S t'} + \sum_{j_S, t=t'} K_{j_S t} \frac{q_{j_S t}}{E_{j_S t}} \qquad \perp \varphi_{t'} \geq 0 \qquad \forall\, t' \tag{5.4}$$

$$\hat{\mathrm{K}}_{t'} \geq \sum_{\tau\geq t}^{\infty} \sum_{k_L} \frac{K_{k_L\tau+\Delta t} b_{k_L t}}{(1+r)^{(\tau-t)}} \qquad \perp \sigma_{t'} \geq 0 \qquad \forall\, t' \geq T_k \tag{5.5}$$

Table 1: List of indices, variables and parameters used in the model

Indices	
$i=j\cup k$	All oil supply projects existing j or new k
$j=j_S\cup j_L$	All existing projects, short-term (tight oil) j_S or other long-term j_L
$k=k_S\cup k_L$	All new projects, short-term (tight oil) k_S or other long-term k_L
$i_S=j_S\cup k_S$	All tight oil projects, existing j_S or new k_S
$i_R=j_R\cup k_R$	All projects of the residual supplier, existing j_R or new k_R
t,t'	Years in the model $\{t_s,t_{s+1},...t_N\}$ where t_s is the start year and t_N the last year modeled (horizon). t' used to index years when new projects are built
τ	All years for projects operating beyond the model horizon $\{t_s,...t_\infty\}$
Δt	Shift in the production profiles for new projects built in year t', $\Delta t=t_s-t'$. As a convention profiles are constructed with t_s as the approval year of new projects
Coefficients	
Supply coefficients	
$C_{i\tau}$	Production cost profiles projected for all projects in \$/b
$E_{i\tau}$	Projected production profiles for existing projects in MMb
$F_{i\tau}$	Projected production profiles for new projects in MMb
$K_{i\tau}$	Annual projected capital development cost for each project i and year τ in million \$
$\hat{\mathrm{K}}_{t'}$	Financial cap on the total discounted capital of new long-term projects built in t'
$\hat{\mathrm{H}}_{t'}$	Financial cap on the annual capital expenditures for all tight oil projects
r	Interest rate used to discount future cash flows
$M_{i\tau}$	Price index reflecting quality and regional characteristic of each project
T_k	Minimum year when investment decision for new projects can be made
Demand Curve	
$\tilde{g}_t$	Reference GDP growth rate projected for all future years
$\tilde{D}_t$	Reference oil demand for each year in MMb
$\tilde{p}_t$	Moving average reference oil price projected for all future years in \$/b
$\tilde{Y}_t$	Reference world GDP for all future years in million \$
Variables	
Primal	
$b_{kt'}$	Investment in new project k in year t' (unitless)
q_{jt}	Quantity produced from existing asset j in year t in MMb
$x_{kt't}$	Quantity produced from new project k in year t built in year in t'
Dual	
λ_{jt}	Marginal value on the supply constraint for existing projects j (5.1)
$\mu_{kt't}$	Marginal value on the production constraint for new projects k (5.2)
γ_k	Marginal value on the constraint for investment decisions (5.3)
φ_t	Scarcity premium on the financial constraint for tight oil projects (5.4)
σ_t	Scarcity premium on the financial constraint for new long-term projects (5.5)
p_t	Market clearing price on the oil demand constraint (6)
Dependent variables	
D_t	Demand for oil as a function of the moving average oil price and the world GDP in MMb
Y_t	World GDP per year in million \$
$\bar{p}_t$	Moving average of the market-clearing price in \$/b

The model is run annually over the period t, where t_s is the start year and t_N is the model horizon year. The orthogonal dual variables of each (complementarity) constraint are defined on the right-hand side of each equation in (5).

$$\sum_j q_{jt} + \sum_{kt'} x_{kt't} \geq D_t \qquad \perp \; p_t \geq 0 \qquad \forall it \tag{6}$$

Suppliers maximize profits π by selling oil production from existing projects j and new projects k at the market price p_t that clears demand. The supply model is connected to the equations for global oil demand (i.e., equations (1) and (2)), through the independent demand constraint (6). It sets the lower bound on the independent production variables for existing projects q_{jt} and new projects $x_{kt't}$ built in period t'. In this formulation, all suppliers are represented as competitive price takers. As the model applies an aggregate global oil demand it does not account for transportation activities. The complete competitive equilibrium problem including the optimality conditions of the supply and demand models is provided in the online Appendix A.1.

Supply decisions are modeled at the project level along two different piecewise linear supply curves; short-run costs for existing projects, and long-run costs for new projects. The linear supply activities are constrained in equations (5.1) and (5.2) using the capacity coefficients E_{jt} for existing and F_{kt} for new projects, respectively.

The short-run supply curves are based on marginal production cost coefficients C_{jt}. The first term in the profit function is the corresponding net revenues. The present value (PV) of the annual profits over the model horizon is calculated using the interest rate r relative to the start year. The coefficient M_{it} is used to correct the price paid to each project accounting for crude quality and regional markers (e.g., Brent versus WTI).

The long-run supply curves include the supplier's decision to develop new projects $b_{kt'}$ for production $x_{kt't}$. These investment decisions are defined as continuous and unitless variables scaled by the production projects F_{kt} in (5.2), with the upper bound on the sum of $b_{kt'}$ over the model horizon set to one in equation (5.3). The coefficients $K_{k\tau}$ are the annual capital development costs of new projects where τ includes the years that a project operates beyond the model horizon t_N. The remaining terms of the profit function are the net present value (NPV) of long-run projects: net revenues within (second line) and beyond (third line) the model horizon, less the PV of annual capital expenditures over the project's lifetime (fourth line).

Revenues for new projects operating beyond the model horizon $\left(\tau > t_N\right)$ are calculated assuming the oil price is fixed to the value from the model horizon year, p_{t_N}. The coefficients of the production profiles $\left(C_{kt+\Delta t}, F_{kt+\Delta t}\right)$, as well as $M_{it+\Delta t}$, are shifted by $\Delta t = t_s - t'$. This captures time lags between the year the project is selected for development within the model and the default approval year used to construct the coefficients (as a convention set to the model start year t_s).

Investments are also categorized as short-term (all tight oil projects) under the index i_S, or new long-term projects by k_L. The latter includes all other developments (conventional oil, oil sands, heavy oil, NGL, and condensates) that generally involve multi-year investment lags and production profiles. Tight oil projects are characterized by short development lead times and fast decline rates, with the majority of a single well's production occurring in the first year (Kleinberg et al. 2016). For this reason, we account for rolling investments in all tight oil projects by embedding capital development costs in the cost coefficients $C_{i_S t}$, expressed as the breakeven cost. Producers effectively make only one decision: continue existing tight oil projects or develop new capacity if the total unit production cost (operating and development) is lower than the current price.

Equations (5.4) and (5.5) represent additional financial constraints (each year) tight oil, and the total PV of new long-term projects, respectively. They introduce a scarcity premium on capital available for projects that are profitable but exceed the investment cap $\hat{H}_{t'}$ for tight oil and $\hat{K}_{t'}$ for new long-term projects. The constraints prioritize investment by profitability as described in more detail in online Appendix A.1.

An alternative approach to model supplies would be to employ a reduced-form supply curve. For example, Huppmann and Holz (2012) develop a model to investigate market power in the global oil market. Each node in their model represents a single continuous non-linear Golombek supply curve (Golombek et al. 1995). However, the authors only consider a single year and neglect investment decisions and depletion.

One can also design a structural equation based on the price elasticity of supply rather than using a supply curve. This provides a more aggregate representation of production and investment decisions. It can be useful for modeling longer-term trends and time horizons, and when detailed supply data may not be available. The dominant firm-competitive fringe model developed by Golombek et al. (2018) employs this technique. The authors investigate the exercise of market power by OPEC from 1986 to 2016, and drivers of long-run oil price trends, including GDP and supply depletion.

As discussed below, since our model assumes perfect competition, we do not explicitly define the strategic behavior of the dominant firm. However, we construct a modified version of the model as a reference residual supplier scenario with predefined price targets. We then compare the results of this scenario against a purely competitive market, from the perspective of the residual supplier. In this case, the residual supplier is assumed to supply a quantity of oil needed to produce the target price in each year, with the competitive fringe responding as a price taker to fill the supply gap. This is achieved by simply adding upper and lower bounds to the market price complemented by dual variables representing the supply additions or removals required by the residual supplier, respectively. The corresponding complementary slackness constraints are described in the online Appendix A.2.

The equilibrium model is solved assuming either myopic supplier behavior with a rolling horizon or forward-looking behavior. In the latter, we assume suppliers have perfect foresight over the model horizon, and therefore we do not apply a rolling horizon. On the other hand, as Spiro (2014) indicates, a short (myopic) time horizon removes the scarcity consideration of the oil producer. Then, the current demand and extraction cost will determine the production level. This is similar to the myopic supplier behavior in our model with a rolling horizon providing suppliers imperfect information on future market conditions.

A myopic supplier does not factor in the longer-term exhaustibility of reserves. However, work by Hart and Spiro (2011) finds that scarcity or Hoteling rents that would result from resource depletion have historically been marginal or absent in oil markets, and that other factors play a stronger role in shaping oil prices.

We found that when applying the financial constraints on long-term investments (see equation (5.4)), the size of the rolling horizon had a very small impact on the market equilibrium. In this case, we apply an extremely myopic approach with the suppliers only considering information from the current year. The model is then solved using the recursive method described in the online Appendix A.3.

2.4 Supply calibration

Rystad Energy's Ucube (Rystad hereafter) upstream oil and gas database is used to calibrate the linear oil supply activities represented in (5), including OPEC members. In the online Appendices A.5 and A.6, we provide additional descriptions of the supply data and methodology used by Rystad, including the characterization of tight oil fields, gas condensates, and other liquids. We present also aggregate supply curves and describe data aggregation methods used to reduce the number of supply activities in the model and improve model performance, without severely compromising the resolution of the supply curve.

Rystad supply data is widely used by scholars in this field, as well as the IEA, and has also found a place in the academic literature. Aune et al. (2015) used Rystad data to calibrate oil and gas production coefficients in an analysis of Russian gas market liberalization. Asker et al. (2019) studied misallocation of oil production within OPEC and non-OPEC countries using Rystad's upstream oil industry data. As discussed above, Bornstein et al. (2019) studied structural changes in the oil market in a general-equilibrium model that relies on Rystad data. Rystad supply data was also used to measure the effect of subsidies for U.S. crude oil production (Erickson et al. 2017), and to construct global oil supply elasticities (Erickson et al. 2020).

Rystad supply data is characterized by quality, field type, location, and ownership. This allows us to capture country-level supply changes and disruptions (e.g. the attack on Saudi Arabia's oil production in September 2019). For each country, the database provides distinct resource endowments, cost structures, financial, technical, and geopolitical constraints. We extract data on individual projects for the projected annual production (including expected approval year and development lead times for new project), marginal production costs C_{it}, and capital development costs $K_{it'}$, all in real 2019 terms.

For tight oil, we assume that on an annual scale the time in years between project approval and start of production is negligible. Tight production costs are set to breakeven costs provided by Rystad, assuming projects are available for production in the same year the investment was made.

Supplies are also differentiated by quality, field type, location, and ownership, providing a detailed representation of different supply categories. We extract data on crude quality ranked by the American Petroleum Institute (API) gravity scale, sulfur content, and regional price differentials, such as the Brent-WTI spread. Table 2 lists crude quality indices (a) and examples of regional Brent/WTI spreads (b), providing an overview of the indices applied at the project level. First, prices for a given project are determined by dividing the annual revenues by its production. The prices are then compared to Rystad's Brent outlook to determine a value for the index applied to each project, M_{it}.

Supplier profits are calculated using a discount rate of 10%, a standard value applied in the oil industry and related literature (e.g., Powell, 1991; Gately, 1995). As a robustness check, we also calibrated the supply model using a 15% discount rate and found that using a higher rate had a minor impact on equilibrium prices and demand.

We calibrate OPEC production data to reflect the total sustainable production capacity of each member country, defined as the capacity that can be put into production within 90 days, based on data from IEA's monthly oil market report (IEA 2019a). Spare capacity is defined as total sustainable capacity minus annual production for each member country. Our analysis excludes some OPEC members (Ecuador, Congo, Gabon, Equatorial Guinea, Nigeria, and Venezuela) because of discrepancies between projected production in the IEA's monthly oil market and self-reported production levels, and they do not hold significant spare capacity.

Table 2: Examples of quality (a) and regional (b) price indices used in the model

(a) Price correction by product quality

Quality	Markdown
Light Crude	1
Regular Crude	0.993
Condensate	0.99
Heavy Oil (API 20—23)	0.957
Sour Crude	0.936
Synthetic Crude	0.908
Heavy Oil (API 15—19)	0.907
Extra Heavy Oil	0.901
Bitumen	0.624
Other liquids	0.512

(b) Brent-WTI price spread

Year	Brent/WTI
2019	1.15
2020	1.15
2021	1.18
2022	1.12
2023	1.08
2024	1.08
2025	1.08
2026	1.08
2027	1.07
2028	1.07
2029	1.07
2030	1.07

Source: KAPSARC analysis, Rystad.

2.5 Calibrating investments

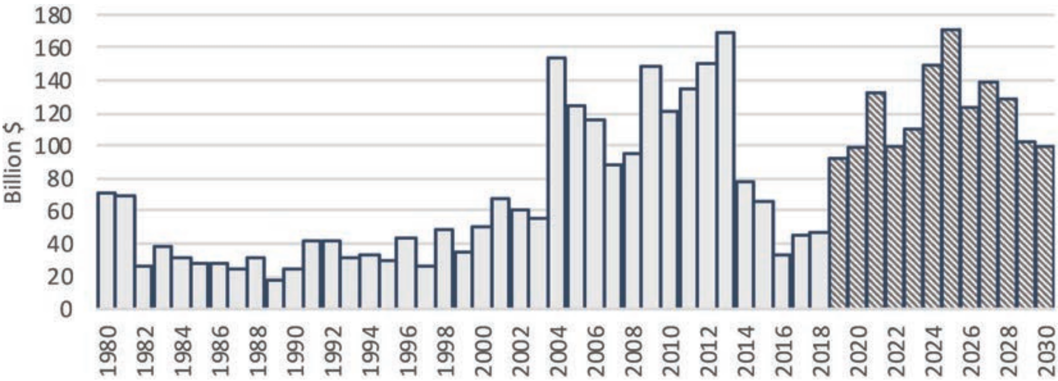
We utilize Rystad data on new oil projects planned between 2020 and 2050. The model is initially calibrated so that all projects can be approved in any year within the horizon if they are profitable. An illustration of the corresponding supply curves is provided in the online Appendix A.6 (see Figures A.1 to A.3). However, under this assumption, the total capital committed each year can greatly exceed the range of values observed in the oil market.

Although many projects may be profitable, numerous factors exogenous to our basic supply optimization constrain potential investments. The amount of capital available globally for the development of new oil projects is limited and can be influenced by global megatrends (such as shifts in funds allocation due to environmental concerns). To address this, we simulate the oil price under different configurations of the investment constraints in (5.4) and (5.5), detailed in the following scenario design section.

Figure 1a plots the present value of capital (in real 2019 dollars) approved annually for new conventional-oil projects between 1980 and 2030, derived from the Rystad database. The values vary significantly during this period, averaging \$46 billion during the 1980s and 1990s and \$125 billion from 2004 to 2014, before the mid-decade crash in oil prices. Based on Rystad's outlook, capital commitments average \$123 billion from 2020 to 2030.

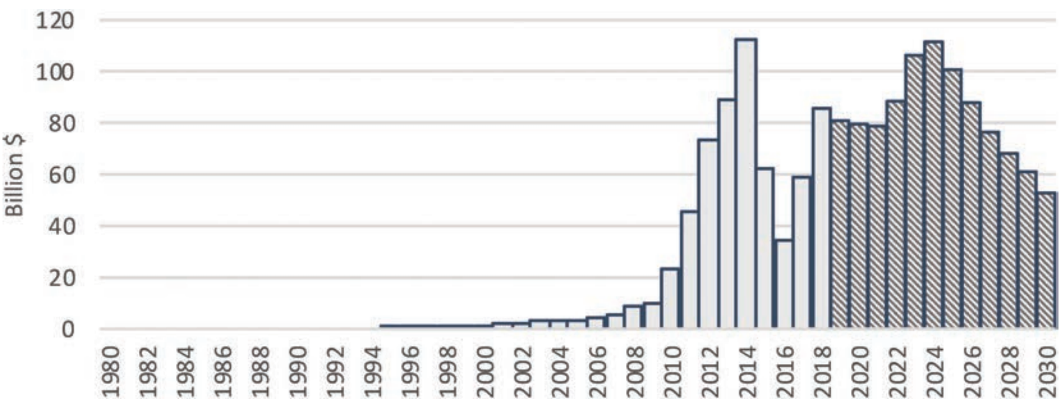
Figure 1b shows the annual capital expenditures on tight oil investments from 1980 to 2030, rather than the PV of capital over the project's lifetime. This captures the short-term nature

Figure 1a: Aggregate PV of capital committed to all new non-tight oil projects annually



Source: Rystad, KAPSARC Analysis.
Note: Values beyond 2018 (patterned area) are as projected by Rystad.

Figure 1b: Total annual capital expenditures on tight oil projects



Source: Rystad, KAPSARC Analysis.
Note: Values beyond 2018 (patterned area) are as projected by Rystad.

of funding for these projects to drill new wells. The rapid expansion after the year 2000 reflects the U.S. tight oil boom and the expected future capital required to continue growth in production.

Rystad's outlook for potential tight oil production sees U.S. output more than doubling from an average output of 6.4 MMb/d in 2018 to a peak of about 17 MMb/d in 2025. The outlook is based on Rystad's assessment of commercially viable projects, at a WTI price in the range of $55/b to $70/b. The 2017 World Oil Outlook (OPEC 2017) and the WEO Stated Policies Scenario (IEA 2019b) both project slower growth in tight oil production, with global output reaching 12 MMb/d in 2025. Reducing the annual capital invested in tight oil projects to half of the levels projected by Rystad generates similar production levels. We therefore introduce this alternative scenario to reflect the views of these more conservative outlooks.

3. SCENARIO DESIGN

We design scenarios to assess the medium-term consequences (i.e., up to 2030) for the world oil market. This includes the competitive scenarios assuming all oil producers behave as price takers (no residual supplier). In our reference scenarios either OPEC cooperates, or Saudi Arabia operates alone, as the residual supplier of the world oil market. The residual supplier targets the prices from the WEO Stated Policies Scenario (IEA 2019b), used to calibrate the demand side given in equations (1) and (2).

The competitive scenarios offer an alternative, restructured view of the world oil market. We simulate both the reference and competitive scenarios under different constraints to capture a variety of conditions under which the oil market could evolve. The most relevant being bounds on the capital available for investment in tight oil and new long-term projects represented in equations (5.4) and (5.5), respectively. The model is tested first with no constraints on the approval of new projects. We then simulate the competitive market with the minimum approval year for every new project set to the value reported by Rystad. Finally, we allow the model to select projects based on profitability (ignoring approval year) within a given investment cap.

The reference residual supplier scenario offers a perspective of the future oil market with continued OPEC coordination. It also offers a review of the demand (IEA) and supply (Rystad) assumptions used to calibrate our competitive market model. We also run the model under historic conditions (price, demand, GDP growth) reported from 2014 to 2018, as validation of the model and the supply data from Rystad. This period includes major shifts in the world oil prices, coinciding with the rise of tight oil production in the U.S. In this case, we fix OPEC production to levels reported over this period, and solve the competitive model finding a market equilibrium under the short-run production costs of existing capacity from all other suppliers. The results, detailed in the online Appendix B.1, are summarized here as the normalized root mean squared error (RMSE) and correlation coefficients (CC) relative to the historic data. They are 0.093 and 0.97, respectively, for demand. 0.11 and 0.95, respectively, for price. These simulations suggest that our model performs well in reproducing observed data and provide a straightforward verification of the Rystad supply data under historic market conditions.

A key output is the residual production needed to support these mid-term outlooks. The financial constraints have a direct impact on the required production, market share and revenues of the residual supplier. For a given level of investment, we develop a simple comparative financial analysis of the residual supplier under the reference scenarios (cooperative and non-cooperative) versus a purely competitive oil market.

First, we assume that the group of OPEC members, with production quotas in 2018, collectively serve as the residual supplier and that they coordinate production in proportion to their total capacity. Given the history of oil markets and that Saudi Arabia is the largest oil exporter and maintains most of the world's spare capacity, we run an alternative case in which Saudi Arabia acts as a residual supplier without support from the rest of OPEC.

It should be noted that the above scenarios are purely hypothetical. Comparing the simulation results from different scenarios will serve to illustrate how and to what extent market structure affects market outcomes (supply, demand, price) as well as oil revenues for Saudi Arabia.

3.1 Financial constraints for new long-term projects and tight oil

For long-term projects we simulate various investment constraints within the range of historic values reported in Figure 1a. Between 2020 and 2030, the Rystad data projects that the average annual capital committed to new projects is $132 billion in present value terms. In our *Rystad investment plan* scenario the model can invest in new projects on or after their projected approval year only.

Next, we simulate alternative scenarios in which new projects can be developed up to an annual cap on the present value of approved capital. Instead of following the project approval years from Rystad, any project approved between 2020 and 2050 can be built. The constraints and corresponding scenario labels are $75 billion, $100 billion, $125 billion, and $150 billion caps. These differ from the standard Rystad plan because we assume suppliers can prioritize projects according to profitability. The investment cap is introduced as a calibration constraint aiming to produce realistic outcomes. It has a profound impact on the model since it amounts to introducing a scarcity premium on the available capital (the dual variable associated with the cap). Every invested dollar implicitly costs a dollar plus the scarcity premium. The smaller the cap, the higher the scarcity premium and the implicit cost of investment (which is endogenously determined by the model). This provides a straightforward approach to simulate a range of constraints, while allowing flexibility in project approvals, including accelerated development of new projects by OPEC members.

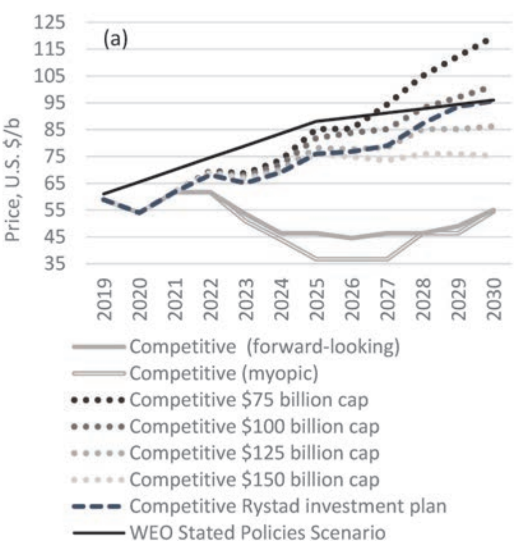
Decisions related to tight oil production are constrained by the commercial outlook provided by Rystad, reaching a peak of about 17 MMb/d in 2025. We assume suppliers can develop any tight oil field, up to the maximum production level, if prices exceed the breakeven point. To restrict tight oil production to near 12 MMb/d we implement a *tight oil cap* scenario limiting annual investments to 50% of the Rystad projections.

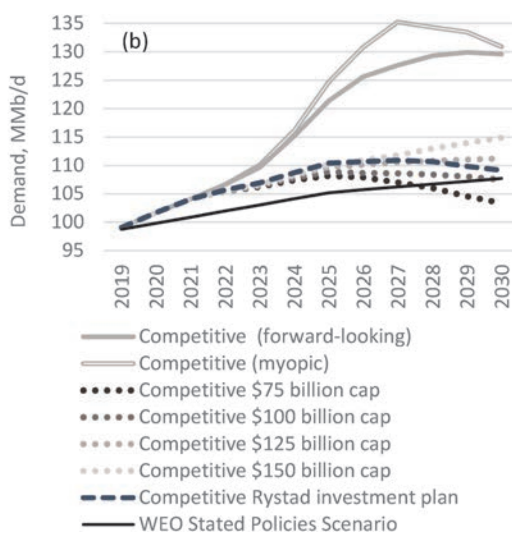
4. MODEL ANALYSIS AND RESULTS

In this section, we will analyze the market equilibrium in the competitive market scenario with different investment constraints and conduct a sensitivity analysis with respect to the model demand parameters. We also examine the impact of these scenarios on the production and revenue of the primary residual supplier (i.e., Saudi Arabia) with and without support from other OPEC members.

Figure 2 compares oil price (a) and demand (b) trajectories from the models of perfect competition (no residual supplier scenario) with the reference WEO levels used to construct the

Figure 2: World oil price (a) and demand (b), WEO Stated Policies versus the competitive scenarios





Source: IEA (2019b) World Energy Outlook, KAPSARC analysis.

residual supplier scenario.[4] We include results for the competitive market model with no investment constraints under both the forward-looking and myopic supplier assumptions. We then simulate the competitive market under the different investment constraints described in section 3.1; the Rystad investment plan and the investment caps ($75 billion, $100 billion, $125 billion, and $150 billion). We apply the forward-looking supplier assumption in these cases; however, given binding investment constraints in these scenarios, the results do not differ significantly with myopic suppliers.

4.1 Oil price and demand dynamics: cap on long-term investments

Under the competitive market scenarios with unconstrained investments (forward-looking and myopic in Figure 2), the present value of capital approved for new projects exceeds $1.6 trillion in 2020. This surpasses historic investment levels reported in Figure 1 and drives prices below $55/b after 2023 with a rapid acceleration in demand growth. It is very unlikely that such aggressive investments would materialize based on profitability alone. These two scenarios illustrate the impact of applying myopic versus forward-looking supplier behavior without binding investment constraints. In the latter, producers expect a downward trend in prices, withholding approval for projects that become unprofitable below about $45/b.

Under the constrained scenarios the difference between the myopic (not shown) and forward-looking assumptions becomes much less pronounced because the investment constraints are binding in both cases, resulting in nearly identical sets of approved projects and available capacity.

The level of the constraint does alter the resulting equilibria significantly after 2024 as new capacity ramps up and replaces declining production from existing projects. Under the Rystad investment plan and the $150 billion cap, prices between 2020 and 2025 average $11/b (14 percent) below the WEO reference prices. However, if the current slow-down in long-term project approvals persists (below $100 billion), prices recover faster and could exceed the WEO reference.

4.2 Oil price and demand dynamics: tight oil investments

In Figure 3 we show price (a) and demand (b) for scenarios where tight oil investments are capped at 50% of the levels projected by Rystad.

In Figure 3a, a slowdown in the growth of tight oil production causes both average prices and price variation to increase. The standard deviation of the annual rate of change in oil prices increases by at least 150 percent, and up to 255 percent, compared to the corresponding scenarios without a cap on tight oil. This holds even when assuming stronger investments in conventional long-term production. This result shows that a decline in the capacity of tight oil projects restricts its ability to balance the market as a source of marginal production.[5]

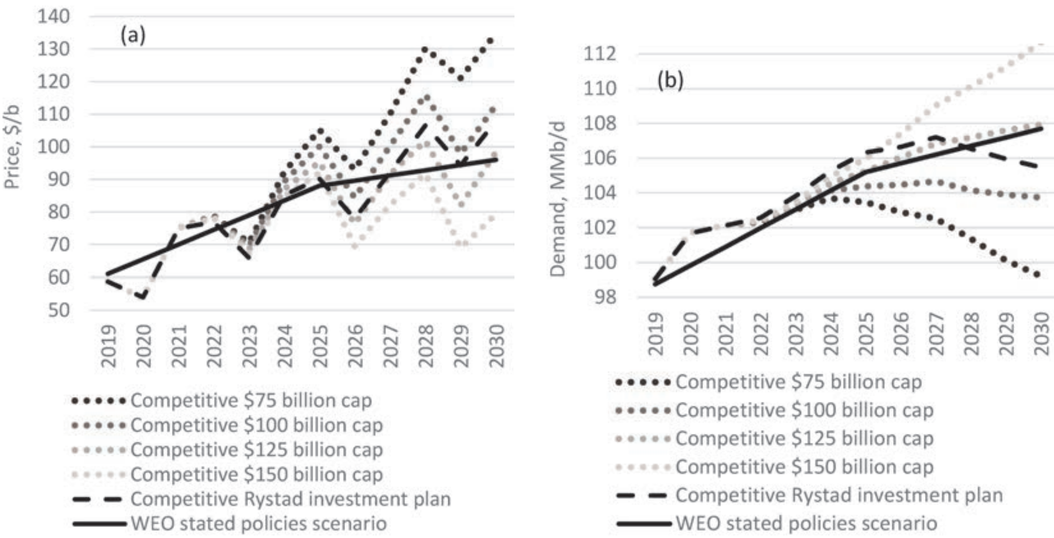
Under the range of investment assumptions considered, prices recover much faster than in Figure 2a. As a result, the market could experience a ramp-up in investment in long-term projects, in response to increasing prices. Only under the accelerated approval of new long-term projects (i.e., the $150 billion cap), do the competitive prices remain below the WEO reference after 2025.

In Figure 3b total demand drops well below the reference scenario after 2024, when the average annual capital committed to long-term projects is capped below levels projected by the Rys-

4. Results obtained using a discount rate of 10%. Additional competitive scenario results are provided in the online Appendix B.2 using 15% and 20% discount rates, showing only minor changes to the model equilibrium.

5. A Rystad study (Rystad 2018a) finds amplified short-term price volatility when U.S. tight oil capacity increases. However, the methodology and data frequency differ from those employed in this study.

Figure 3: World oil price (a) and demand (b): WEO Stated Policies versus the competitive scenarios assuming a 50% reduction in capital expenditures on short-term tight oil projects



Source: IEA (2019b) World Energy Outlook, KAPSARC analysis.

tad investment plan (i.e., $75 billion and $100 billion). We observe peak oil demand in both these scenarios, as well as under the Rystad investment plan.

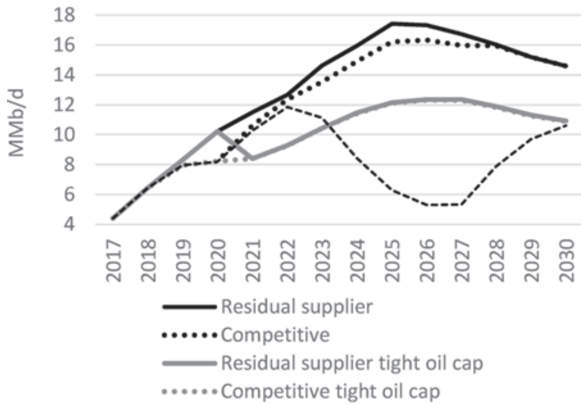
Note that under the residual and no residual supplier scenarios we apply the same constraints on investments in new projects and find them to be binding in both cases. Under the lower investment constraints (e.g. $75 billion and $100 billion) the total sustainable capacity is less than the demand in the WEO. In this case, the residual supplier would have to accelerate the capital development of existing projects to produce above sustainable production levels and balance the market following the WEO projections.

Finally, Figure 4 displays the global tight oil production in different scenarios, with and without investment caps. In the scenarios with investment constraints (residual supplier and competitive) we apply the $150 billion annual constraint on new conventional projects. The black dotted and dashed lines illustrate how tight oil production responds to the increased production from conventional projects and decline in prices. The dashed line (competitive w/o investment cap) represents the scenario with myopic suppliers and no investment caps. It shows the sensitivity of tight oil production as prices dip below $60/b after 2022. Below $45/b production drops rapidly, with output in 2026 falling to pre-2018 levels but recovering as the price recover to $55/b by the end of the decade. The other scenarios in Figure 4 are for the Rystad investment plan. In this case, the smaller reduction in prices in the competitive market scenarios results in a smaller reduction in tight oil production, between one and two MMb/d.

4.3 Sensitivity analysis: demand parameters

The price elasticity of demand plays a central role in calibrating how consumers respond to a change in the supply structure. To investigate the sensitivity of our model to our assumptions, we run several scenarios calibrated across a range of both income and price elasticities presented in the online Appendix B.3. As shown in Figure B.3, we find that for the range of income elasticities

Figure 4: Global tight oil production in the residual supplier and competitive market scenarios for the Rystad investment plan (dashed line is without investment constraints)



Source: Rystad, KAPSARC analysis.

of interest (0.25 to 1.0) the impact on the model equilibria is very small relative to changes in the price elasticity (Figure B.4).

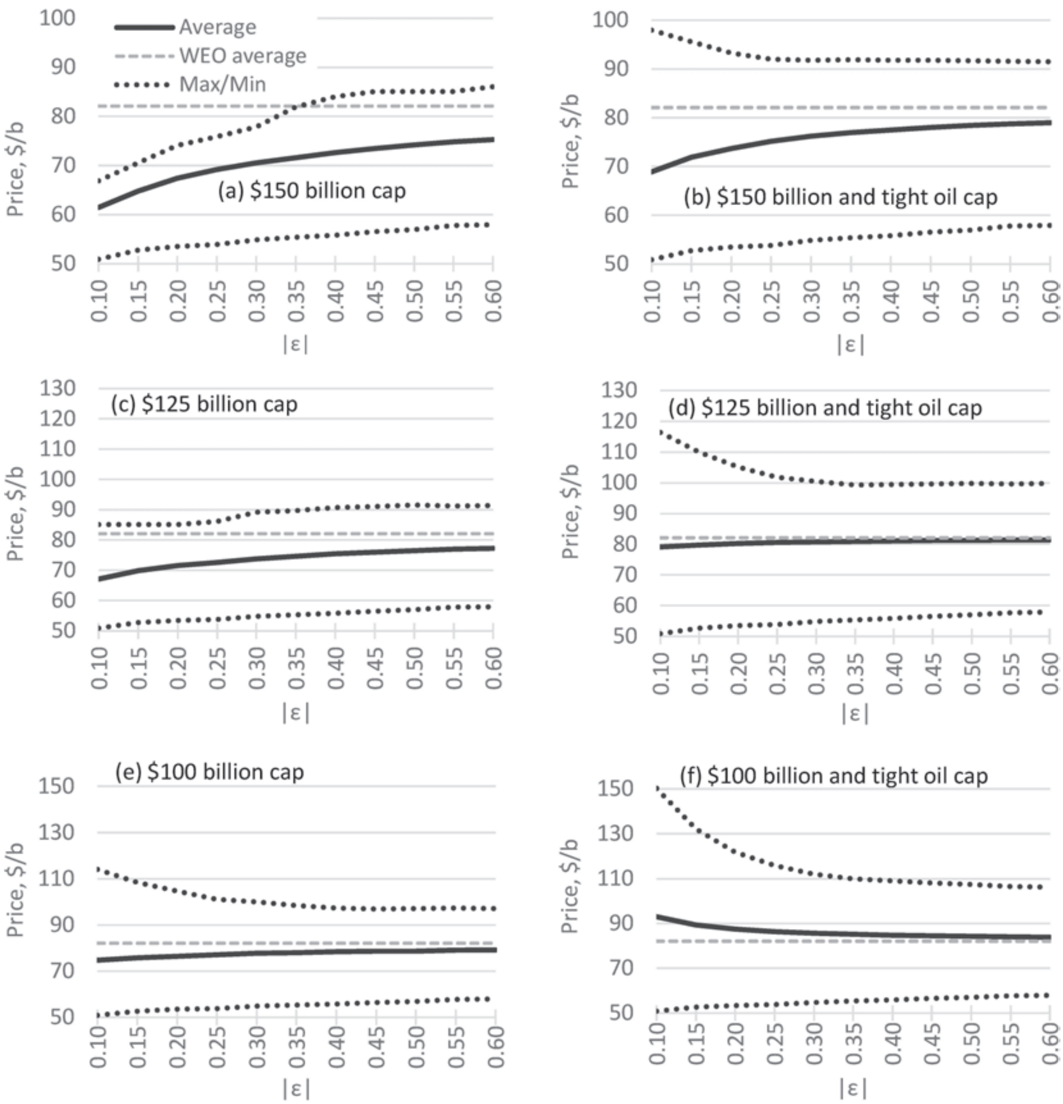
The price and demand results under three different price elasticity assumptions (-0.1, -0.25, and -0.5) are presented in online Appendix B.3.2. As expected, with consumers more responsive to the change in price, demand and prices recover faster in the competitive market. Figure 5 plots the average prices from 2020 to 2030 in the competitive scenario (solid lines) across a range of price elasticities of demand: the \$150 billion cap (5a), \$125 billion cap (5c), and \$100 billion cap (5e), and cases including the 50% cap on tight oil (5b), (5d) and (5f), respectively. Dotted lines show the maximum and minimum values, and the dashed lines the average prices from the WEO.

In the scenarios with more relaxed investment constraints (e.g. \$150 billion cap) average prices respond more to changes in the absolute price elasticities. As the price elasticity increases in absolute terms, the demand reacts stronger to lower prices created by additional OPEC production, leading to higher equilibrium prices. As the investment constraints are tightened, average prices flatten out across different elasticities, but exhibit larger variability (in terms of maximum price less minimum price) as originally observed in Figures 2 and 3. Here the results reflect the calibration, with average prices converging towards the WEO reference, while oscillating with greater amplitude due to the higher scarcity premiums on investments generated by the caps.

Figure 5 shows that the relationship between the average price and the absolute value of the price elasticity of demand flips from increasing to decreasing as the investment constraint is tightened. Under the \$100 billion conventional and 50% tight oil investment cap a weak demand response, that is slow to adjust to the tighter supplies, causes more frequent price spikes (see online Appendix B.3.2 Figure B.5) and higher average prices.

In the online Appendix B.4 (Figure B.6), we present additional scenarios calibrated to the reference demand and price projections of the IEO (EIA 2019). Compared to the WEO, calibrating the model to IEO data produces reduced price levels and variability, reflecting the slower price and demand growth projections by the EIA.

Figure 5: Average prices (solid lines) from the competitive scenarios between 2020 and 2030 versus the long-run price elasticity of demand under different investment constraints

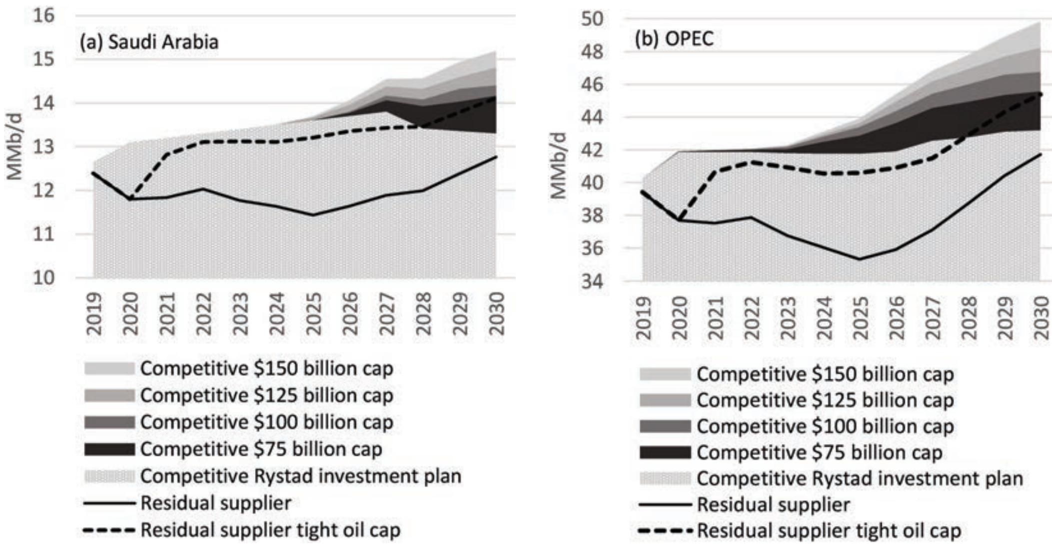


Source: KAPSARC analysis.
Note: Dotted lines are max and min prices of the competitive scenarios, dashed lines are the WEO average.

4.4 Supply dynamics of the residual supplier

Figure 6 shows the growth in Saudi Arabia (a) and OPEC (b) total production and available capacity in a competitive market (shaded areas). The lines represent total production when OPEC coordinates as the residual supplier, with investment decisions constrained to the development plan presented by Rystad. In this case, many OPEC projects are only scheduled for approval after 2030, reflecting a strategy that maintains stable rather than accelerated production. The dashed lines reflect the scenarios with a cap on tight oil with total OPEC production responding to slower growth in

Figure 6: Liquids production by Saudi Arabia (a) and OPEC (b) in the competitive scenarios (shaded areas) and OPEC as the residual supplier with (dashed line) and without (solid line) the 50% cap on tight oil investments



Source: KAPSARC analysis.

unconventional resources. Figure B.7 (online Appendix B.5) shows Saudi Arabia's production when participating as the residual supplier under different investment constraints.

Saudi Arabia's production falls to 11.4 MMb/d, about 2 MMb/d below its capacity, coinciding with a peak in tight oil production in 2025. In this case, OPEC production falls to 35.3 MMb/d, with participating members assumed to coordinate residual production proportional to their total capacity. Historically, Saudi Arabia has shouldered the largest share of production cuts compared to other members. If Saudi Arabia were to organize most of the withheld production (about 6.4 MMb/d), with limited to no support from OPEC, it would face a significant reduction in market share.

Under the 50% reduction in capital invested in tight oil projects, the market share of the residual supplier increases significantly, exceeding 40 MMb/d after 2020. In this case, Saudi Arabia may be better positioned to operate as a residual without support from OPEC. Also, under the tight oil constraint, the residual supplier's production exceeds OPEC capacity under the Rystad investment plan by 2.2 MMb/d. This would require members to accelerate project approvals, as observed in the alternate investment cap scenarios.

In a world with strong tight oil growth, Saudi Arabia needs to coordinate production cuts with other producers to maintain production above 10 MMb/d at the stated price target. This might include countries outside OPEC, such as Russia and other producers participating in the OPEC+ group (Gnana 2019). The idea that OPEC may require support from other countries outside of the organization has been explored in the study by Volkmar (2018). Saudi Arabia's ability to provide stability for the global oil market faced additional pressure during the unprecedented decline in global oil demand resulting from the coronavirus pandemic, elevating the need for coordinated production cuts by OPEC+.

4.5 Economics of the residual supplier

In light of the findings above, we investigate whether serving as a residual supplier can increase Saudi Arabia's oil revenues relative to a purely competitive market behavior, assuming the Kingdom can independently maintain its market share as the primary residual supplier, or do so with support from OPEC (and other partners).

To answer this question, we estimate Saudi Arabia's free cash flows, defined as net revenues less annual capital expenditures, under the competitive and residual supplier scenarios. We calculate the present value of the cash flow in the residual supplier scenario less the cash flow in the competitive scenario for two cases: OPEC jointly acting as residual supplier and Saudi Arabia acting alone.[6]

Our NPV calculation provides an estimate of the profits gained (or lost) by Saudi Arabia assuming a competitive market structure. However, one should be careful in interpreting this measure of the market value attained by the residual supplier. First, matching the price and demand equilibrium from the WEO Stated Policies assumes perfect coordination of residual production by different producers (e.g. OPEC). Second, the residual supplier could make a production decision that is not consistent with the WEO's scenario. Our analysis is simply used to identify a directional shift in cash flows of the competitive scenario compared to the WEO reference case.

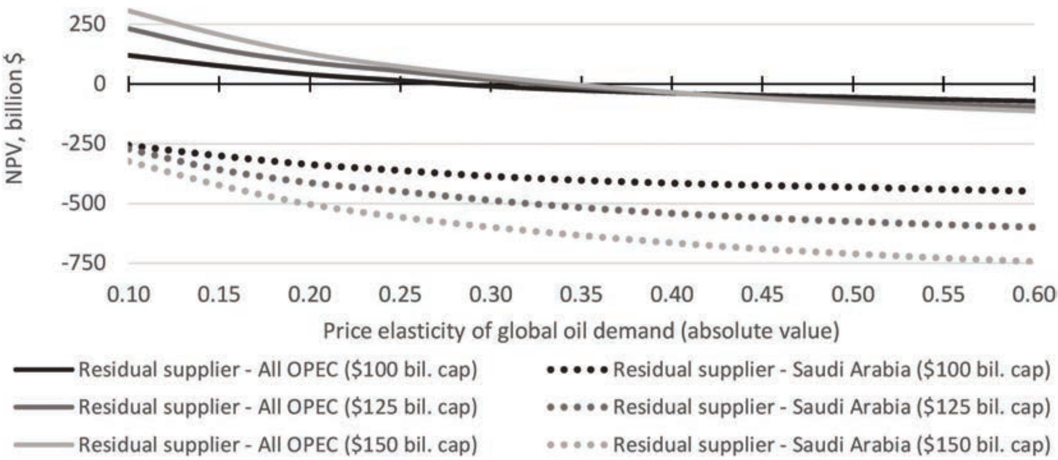
Figure 7a shows that the NPV of the cash flows received by Saudi Arabia when OPEC acts as a residual supplier is greater than the NPV of Saudi Arabia's cash flows in a competitive market if the absolute value of the price elasticity of global demand is smaller than 0.35. As shown earlier in Figure 5, the average price in the competitive market is smaller than in the WEO Stated Policies Scenario when assuming relatively low price elasticities.

When acting as a residual supplier without support from OPEC, Saudi Arabia's profits are always lower than in the competitive scenarios (> $250 billion). In fact, as shown in Figure B.7, Saudi Arabia's production as the sole residual supplier is significantly lower than in the competitive scenario, with its market share falling below nine percent and down to six percent in extreme cases. With this relatively small market share, Saudi Arabia is clearly worse off acting alone as the residual supplier.

When applying the tight oil cap in Figure 7b the residual supplier's market share and cash flows increase. However, the additional supply constraint also leads to higher average prices in the competitive market, pushing the NPV curve down when the tight oil cap is reduced. In this case, the difference in Saudi Arabia's NPVs (i.e., residual supplier minus competitive market) is positive up to a price elasticity of 0.4 with strong investments in conventional projects ($150 billion cap) and coordination with OPEC. However, under the $100 billion investment cap, with conventional investment declining the NPV curve falls and the slope changes sign. The NPV of the cash flows received by Saudi Arabia is then always higher in a competitive market, irrespective of the value assumed for the price elasticity of the global demand.

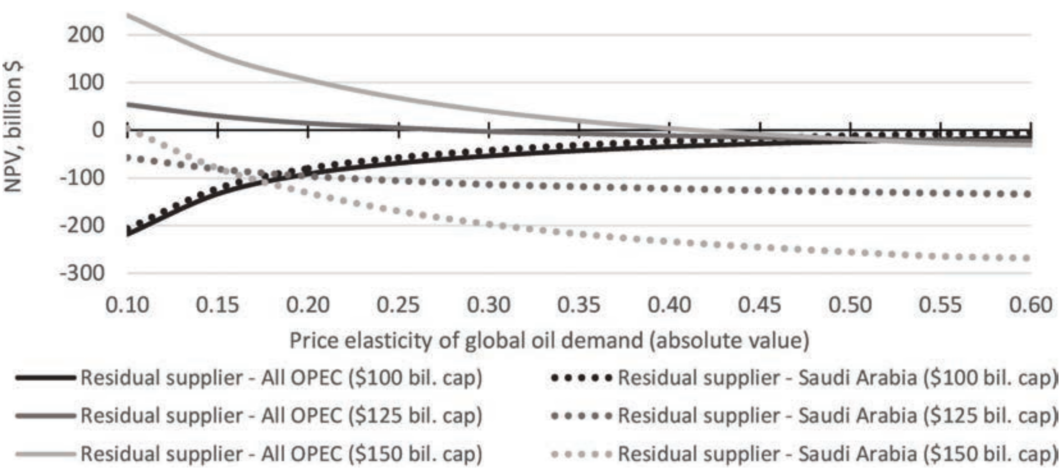
6. We assume that the residual supplier targets the same reference price regardless of whether all OPEC or only Saudi Arabia serves as residual supplier. Although Saudi Arabia might reduce its target price to preserve its market share if operating solo, we do not include such an adjustment in our estimates of its incremental cash flows. It is also worth noting that for the NPV analysis to be consistent with the above simulations, we use a 10% discount rate to calculate the NPVs, although from a public economics perspective a lower discount rate might be applied to oil-related cash flows in Saudi Arabia (Pierru and Matar, 2014). As a robustness check, we also calculate the NPVs using a discount rate of 4% for Saudi Arabia. We find that our qualitative findings are robust to using lower discount rates.

Figure 7a: NPV of Saudi Arabia's incremental cash flows (cash flow in residual supplier minus cash flow in competitive scenario) versus the price elasticity of demand



Source: KAPSARC analysis.
Note: Residual supplier as OPEC (solid lines) or only Saudi Arabia (dotted lines).

Figure 7b: NPV curves as described in 7a including the 50 percent cap on tight oil investments



Source: KAPSARC analysis.
Note: Residual supplier as OPEC (solid lines) or only Saudi Arabia (dotted lines).

5. CONCLUSION

This study introduces a competitive market model for the supply-demand equilibrium of the global oil market without a residual supplier. The model includes detailed linear supply activities and explicit financial constraints, differentiating production and investment decisions. We calibrate the model to a reference demand outlook curve, including price elasticity of global demand and income elasticity assumptions.

This study presents several scenarios across a range of investment constraints for conventional and tight oil projects, solved from the year 2020 to 2030. Our competitive scenarios demonstrate how prices and demand could respond in a market with no residual supplier. Under our central annual price elasticity assumption ($\varepsilon = -0.25$), between 2020 and 2025 prices decline on average by up to $11/b (14 percent) relative to reference prices. Then, prices recover to the reference residual supplier scenario levels before 2030 because of demand response and the depletion of existing conventional production.

Our analysis indicates that prices under our competitive market scenarios have a high sensitivity to growth in tight oil production. Price variability, measured as the standard deviation in the annual change in prices, increases substantially (by at least 150%) when capping tight oil investments to half of the levels projected by Rystad. In this case, the ability of new tight oil projects to balance the market as a source of marginal production is reduced.

The study finds that compared to the competitive scenario, Saudi Arabia does not benefit from acting alone as a residual supplier. The fundamental reason behind this result is that Saudi Arabia's market share is relatively small, and the price elasticity of global demand is too high. However, it is in Saudi Arabia's interest to continue to be part of a larger OPEC/OPEC+ group that works collectively as a residual supplier. When assuming OPEC is the residual supplier, this holds if the absolute value of the long-run annual price elasticity of global demand is less than 0.35.

When all countries behave competitively, a reduction in the global investment cap results in an increase in the cash flows of low-cost producers. The cap implicitly raises the investment costs for all projects, but low-cost producers remain profitable. This, for instance, means that Saudi Arabia would benefit from a decrease in the financial resources available for the global upstream oil sector—for example, due to environmental concerns of international investors.

The results also suggest that cooperation between Saudi Arabia and other producers can reduce the sensitivity of Saudi Arabia's oil revenues to tight oil production growth. This finding supports the view that, with the tight oil revolution, enlarging the collective role of residual supplier to other non-OPEC producers may be necessary for Saudi Arabia to maintain higher oil revenues than those it would earn in a competitive market with no residual producer.

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