Diminishing Returns:

Capital Efficiency and Azerbaijan's Oil Revenue Decline

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Abstract

Azerbaijan's oil revenues are conventionally understood as a function of two variables: production volume and world oil price. This article shows that this two-factor model is no longer sufficient to explain the country's fiscal trajectory. During the first half of 2026, Azerbaijan's oil and gas revenues continued to decline even as global oil prices rose sharply amid instability in the Strait of Hormuz — a combination the standard model cannot account for. Drawing on a sixteen-year dataset (2010–H1 2026) covering national production, price, and revenue, together with field-level data for the BP-operated Azeri-Chirag-Gunashli (ACG) block and SOCAR's own operations, the article identifies two structural forces operating beneath the price-and-volume surface: a sustained decline in the capital efficiency of ACG's investment (output generated per dollar of capital and operating expenditure) and a parallel decline in the drilling productivity of SOCAR's own fields (output generated per metre drilled). Both indicators point to the same underlying phenomenon, field maturation, but through different mechanisms and with different implications for producers, regulators, and fiscal planners. The article concludes that continued reliance on price and volume alone as explanatory variables for Azerbaijan's oil revenue trajectory will systematically misstate the country's fiscal outlook, and it proposes a set of institutional and technical responses to the productivity decline documented here.

Keywords: Azerbaijan; ACG; SOCAR; SOFAZ; oil production; oil revenues; oil price; well productivity; capital efficiency; opex; capex; petroleum economics; resource depletion

1. Introduction

Azerbaijan's national oil revenues are conventionally understood as a function of two variables: the volume of oil produced and the price at which it is sold. Table 1 below traces both variables, together with the resulting revenue received by the State Oil Fund of Azerbaijan (SOFAZ), across sixteen years. Read in isolation, that table appears to confirm the conventional model reasonably well: Azerbaijan's peak production year, 2010, also produced one of its highest revenue years; the revenue trough of 2020 coincided with both a production decline and a collapse in world oil prices; and the revenue peak of 2022 coincided with an unusually high Brent price environment.

The first half of 2026 breaks this pattern. Instability in the Strait of Hormuz pushed global oil prices sharply higher during the period, the average Brent price for H1 2026 reached $87.4 per barrel, among the highest half-year averages of the post-2015 period — yet Azerbaijan's oil and gas revenue for the same period fell relative to the equivalent period in each of the preceding three years. A price-and-volume model predicts that high prices should, all else equal, raise revenue. It does not predict a revenue decline coinciding with a price spike.

This article argues that the missing explanatory variables are not price or volume themselves, but the *efficiency* with which capital and drilling effort are converted into output. This line of inquiry builds on my earlier work identifying structural factors behind Azerbaijan's declining oil revenues (Ibadoghlu, 2024), extending that analysis specifically to the H1 2026 episode and to two efficiency indicators, capital efficiency at ACG and drilling productivity at SOCAR, that had not previously been isolated and quantified in this way. The article examines two indicators that sit beneath the aggregate national statistics: first, the capital efficiency of the BP-operated Azeri-Chirag-Gunashli (ACG) block, the country's single largest oil-producing asset, measured as barrels of daily output generated per dollar of combined capital and operating expenditure; and second, the drilling productivity of SOCAR's own fields, measured as tons of oil produced per metre of well drilled. Both indicators have declined steadily and substantially since 2010, and both point to the same underlying cause: the natural maturation of Azerbaijan's principal oil fields. But they operate through different mechanisms, are documented with very different degrees of public transparency, and imply different policy responses, a distinction this article develops in detail.

2. Data and Methodology

This article draws on four datasets, presented as Tables 1 through 4 below, compiled from a combination of primary company disclosures, sovereign wealth fund statements, and national statistical releases.

Table 1 (national-level, 2010–H1 2026) combines oil production, average annual Brent crude price, and SOFAZ's combined oil-and-gas revenue. The 2010–2025 figures are reproduced from my prior analysis (Ibadoghlu, 2026), which in turn draws on SOFAZ, SOCAR, national statistical sources, and IMF/FRED price series; the H1 2026 addendum is compiled from Trend.Az and APA-Economics reporting, with the price figure calculated as the simple average of the IMF/FRED quarterly Brent series (POILBREUSDQ) for Q1 and Q2 2026.

Table 2 narrows the focus to a four-year first-half (January–June) comparison, 2023–2026, and adds a decomposition of total oil-and-gas revenue into its ACG-specific component, drawn from SOFAZ's own periodic "Revenue and Expenditure Statement" and "Revenues from ACG and Shah Deniz" press releases.

Table 3 presents ACG-specific operational and cost data for five benchmark first-half periods (2010, 2016, 2020, 2025, 2026), drawn from BP Azerbaijan's official H1 results press releases, and derives four efficiency metrics: productivity per well (thousand barrels per day, kbpd, divided by well count), capital expenditure per well, combined capital-and-operating expenditure per well, and, the article's central metric, capital efficiency, defined as production (kbpd) divided by combined capital-and-operating expenditure ($M).

Table 4 presents the equivalent productivity calculation for SOCAR's own fields for 2020–2025, using annual oil production (million tons) divided by total drilling volume (metres drilled). This substitution, drilling metres in place of well count and capital expenditure, was necessitated by a data-availability constraint discussed in Section 5 below: unlike BP, SOCAR does not publicly disclose either its well count or its capital expenditure at a level of granularity comparable to the ACG disclosures.

3. National-Level Trends, 2010–H1 2026 (Table 1)

Table 1. Azerbaijan: Oil Production, Price, Gas Production, and SOFAZ Oil & Gas Revenues, 2010–H1 2026

Year	Oil production (M tons)	Oil price (USD/barrel)	Gas production (bcm)	Oil & gas revenue, SOFAZ (AZN M)
2010	50.8	79.5	26.3	12,656.0
2011	45.6	111.3	25.7	15,257.4
2012	43.4	111.6	26.9	13,117.3
2013	43.5	108.6	29.4	13,108.0
2014	42.0	98.9	29.6	12,319.8
2015	41.6	52.3	28.9	7,369.5
2016	41.0	43.6	29.4	8,320.0
2017	36.7	54.2	28.6	11,029.9
2018	38.8	71.3	30.5	16,645.5
2019	37.5	64.3	35.6	14,614.7
2020	34.5	41.9	37.2	6,587.2
2021	34.6	70.8	43.8	11,894.6
2022	32.6	100.9	46.7	19,698.9
2023	30.2	82.5	48.3	14,519.0
2024	29.1	80.5	50.3	10,197.6
2025	27.7	69.1	51.5	10,266.3
H1 2026	13.3	87.4	25.4	5,743.2

Source: Gubad Ibadoghlu, "Energy, Power, and Repression: Political Economy Insights from Azerbaijan," SSRN, 10 April 2026 (https://ssrn.com/abstract=6554858) (Table 1), plus H1 2026 addendum. Notes: the price series is Brent-benchmarked (IMF/FRED POILBREUSDA/POILBREUSDQ), not the Azeri Light spot price specifically; SOFAZ revenue combines oil and gas receipts under production-sharing agreements; H1 2026 gas production is drawn from Azerbaijan's State Statistics Committee / Ministry of Energy operational data (innews.az, News.az, July 2026).

Three episodes in Table 1 illustrate the conventional price-and-volume model working as expected. Azerbaijan's production peak, 50.8 million tons, occurred in 2010; combined with a healthy $79.5 price, that year produced the second-highest revenue figure in the entire series. The following year, 2011, saw production fall to 45.6 million tons, but the Brent price rose to $111.3, among the highest annual averages of the post-2000 era, and revenue rose to its all-time peak in nominal terms up to that point, 15,257.4 million AZN. At the other extreme, 2020 saw both variables move against Azerbaijan simultaneously: production fell to 34.5 million tons and price collapsed to $41.9 amid the COVID-19 demand shock, and revenue fell to 6,587.2 million AZN, the lowest figure in the sixteen-

year series. In each of these three episodes, the direction of revenue is fully explained by the joint direction of price and volume.

The period since 2022 breaks this pattern with increasing severity. Production has declined every year without exception since 2018 (with the partial exception of a marginal 2021 uptick), falling from 38.8 million tons that year to 27.7 million tons in 2025, a decline of nearly 29 percent in seven years, and a cumulative decline of 45.5 percent from the 2010 peak. Price, by contrast, has been considerably more volatile than production, falling as low as $69.1 in 2025 before rising again. What Table 1 alone cannot explain is the trajectory that becomes visible only once the first half of 2026 is added to the series: a Brent price of $87.4, higher than every full-year average since 2022, coinciding not with a revenue recovery, but with the continuation of the revenue decline first documented in 2023. Explaining that anomaly is the task of Tables 2 through 4.

It is worth noting, before turning to that anomaly, that Table 1's gas production column moves in the opposite direction from oil: national gas output very nearly doubled between 2010 (26.3 bcm) and 2025 (51.5 bcm), driven primarily by the ramp-up of Shah Deniz Stage 2 and, more recently, by rising associated-gas output from ACG. This divergence matters for how the revenue figures in Table 1 should be read, since SOFAZ's combined "oil & gas revenue" line blends both commodities: a rising gas contribution has, to some degree, cushioned the effect of declining oil revenue on the combined total in recent years, and its absence from a narrower oil-only revenue measure would make the oil-side decline documented in this article appear even steeper than the combined figures in Table 1 suggest. The H1 2026 gas figure (25.4 bcm) is not directly comparable to the full-year figures above it and should be read as a half-year total rather than as a break in the multi-year growth trend.

4. The H1 2023–2026 Anomaly (Table 2)

Table 2. Azerbaijan H1 (Jan–Jun) Comparison, 2023–2026: Revenue, ACG Revenue, Production, Price

Year	Total oil & gas revenue (AZN M)	YoY change	ACG revenue (AZN M)	YoY change	Oil production (M tons)	Brent price (USD/bbl)
2023	8,624.3	—	5,691.6	—	15.2	82.3
2024	6,436.5	-25.4%	5,109.0	-10.2%	14.4	79.9
2025	5,743.2	-10.8%	4,427.3	-13.3%	13.7	71.0
2026	4,953.4	-13.8%	4,374.9	-1.2%	13.3	87.4

Sources: SOFAZ official H1 statements (oilfund.az news archive #1595, #1648, #1711, #1771); Ministry of Energy of Azerbaijan; IMF/FRED (POILBREUSDQ).

Table 2 isolates the first-half period across four consecutive years and makes the 2026 anomaly explicit. Total oil-and-gas revenue fell in every one of the three intervening years, but the composition of that decline is analytically important. Between 2023 and 2024, total revenue fell by a striking 25.4 percent, far outpacing the 10.2 percent decline in ACG-specific revenue over the same period, and outpacing the roughly 5 percent decline in production and the roughly 3 percent decline in average price. That gap between the aggregate revenue decline and the ACG-specific decline indicates that non-ACG revenue components, most plausibly gas revenue from Shah Deniz, together with bonus and transit payments that SOFAZ records separately from field-level "profit oil/gas" receipts, fell considerably faster than ACG revenue in that particular year, and is a line of inquiry this article flags for further research rather than resolves.

The pattern reverses in the final year of the series. Between 2025 and 2026, ACG revenue was nearly flat, declining by just 1.2 percent, even as production continued to fall (from 13.7 to 13.3 million tons, a 2.9 percent decline) and price rose sharply (from $71.0 to $87.4, a 23.1 percent increase). A naive reading might treat this near-stability as reassuring, evidence that the revenue decline is finally stabilizing. Sections 5 and 6 argue the opposite: 2026's near-flat ACG revenue, achieved despite a sharply higher price, is itself evidence of deteriorating capital efficiency, because it shows that a 23 percent price increase was almost entirely absorbed by declining output and rising unit costs rather than passed through to revenue.

5. ACG Capital Efficiency, 2010–2026 (Table 3)

Table 3. Azeri-Chirag-Gunashli (ACG) Block, H1 Production, Cost, and Well-Efficiency Metrics (*First-half (H1) figures for selected years, 2010–2026)*

Year	Production (kbpd)	Well count	Opex ($M)	Capex ($M)	Productivity/ well (kbpd)	Capex/ well ($M)	Capex+Opex/ well ($M)	Capital efficiency (kbpd/$M)
2010	827.6	62	190.0	774.0	13.35	12.48	15.55	0.859
2016	655.0	102	260.0	749.0	6.42	7.34	9.89	0.649
2020	498.0	129	268.0	947.0	3.86	7.34	9.42	0.410
2025	327.0	143	259.0	558.0	2.29	3.90	5.71	0.400
2026	323.0	150	268.0	733.0	2.15	4.89	6.67	0.323

Sources: *BP Azerbaijan official H1 results press releases (bp.com/en_az/azerbaijan) for 2010, 2020, 2025, 2026; BP Azerbaijan H1 2016 results for production, well count, and opex (2016 capex is estimated; see note below). Productivity/well = Production ÷ Well count. Capex/well = Capex ÷ Well count. Capex+Opex/well = (Capex+Opex) ÷ Well count. Capital efficiency = Production ÷ (Capex+Opex) — kbpd of output per $1 million of total (opex+capex) spend.*

Table 3 is the analytical core of this article, and its two most important patterns deserve to be stated plainly before they are interpreted.

First, well productivity has collapsed. In the first half of 2010, ACG's 62 producing wells together delivered 827,600 barrels of oil per day, an average of 13.35 kbpd per well. By the first half of 2026, the well count had more than doubled, to 150, while daily production had fallen by more than 60 percent, to 323,000 barrels, an average of just 2.15 kbpd per well. Put differently: it now takes roughly six times as many wells to produce a given volume of oil as it did sixteen years ago. This is the textbook signature of a maturing offshore field: as reservoir pressure declines and the most productive drilling locations are exhausted, operators must drill an increasing number of wells simply to offset the natural decline rate of existing wells, let alone to grow output.

Second, and more consequentially for the fiscal questions this article raises, capital efficiency has deteriorated even faster than the unit cost of drilling a well would suggest. Capex per well fell from $12.48 million in 2010 to $4.89 million in 2026, a 61 percent reduction, reflecting some combination of smaller, cheaper development wells, standardized drilling designs, and BP's own cost-discipline programs following the 2014–2016 oil price collapse. Combined capex-and-opex per well fell by a comparable 57 percent, from $15.55 million to $6.67 million. If cost per well had fallen in step with output per well, capital efficiency, output generated per dollar spent, would have remained roughly constant. It did not: capital efficiency fell from 0.859 kbpd per $1 million spent in 2010 to just 0.323 kbpd per $1 million in 2026, a decline of 62.4 percent. In other words, the well-level cost reductions BP has achieved, while real, have not kept pace with the well-level production decline. Every dollar of capital and operating spend on ACG buys less than one-third of the barrels of daily output it bought sixteen years ago.

This is the mechanism that resolves the 2026 anomaly identified in Section 4. When the Brent price rose 23.1 percent between H1 2025 and H1 2026, ACG's revenue should — under the price-and-volume model, have risen substantially. It did not, because the underlying capital base generating ACG's output was, on a per-dollar-spent basis, producing markedly less than it had the year before, and because capex itself rose by 31.4 percent (from $558 million to $733 million) in the same period without a corresponding rise in output, production continued to fall, from 327 to 323 kbpd. The field required *more* capital to sustain a *lower* output level, precisely at the moment when the world price of that output happened to rise. Absent that capital-efficiency deterioration, the same price increase would have translated into materially higher revenue.

It is also worth noting a scope limitation in the 2016 capex figure specifically: BP's public H1 2016 disclosure did not include an explicit capital expenditure line, and the $749 million figure used in Table 3 is estimated proportionally from confirmed quarterly and full-year 2016 figures. This does not affect the broader trend, the 2010, 2020, 2025, and 2026 figures are all drawn directly from official disclosures, but it should be treated with somewhat greater caution than the other years in the series.

6. SOCAR Drilling Productivity, 2020–2025 (Table 4)

Extending the capital-efficiency analysis in Table 3 to SOCAR, Azerbaijan's second-largest oil producer after BP-operated ACG, and the entity through which the state holds its principal direct stake in the sector, proved considerably more difficult, and that difficulty is itself an empirical finding worth reporting. Unlike BP, which discloses well count and capital expenditure for ACG at half-yearly intervals as a matter of routine public reporting, SOCAR discloses neither figure in a standardized, comparable format. Its periodic financial statements report revenue, profit, and, inconsistently, total capital expenditure at the consolidated group level (encompassing SOCAR's international, midstream, and downstream operations, not only its own upstream fields), but do not report the number of producing wells at all. Constructing a genuinely comparable "capital efficiency" indicator for SOCAR, on the model of Table 3's ACG calculation, is accordingly not possible from public information.

What SOCAR does disclose, with reasonable consistency, is annual drilling volume, the total metreage drilled by its exploitation and exploration operations, alongside annual oil production. Table 4 uses this substitute pairing to construct an analogous productivity indicator: tons of oil produced per metre drilled.

Table 4. SOCAR, Oil Production, Drilling Volume, and Productivity, 2020–2025

Year	Production (M tons)	Drilling volume (metres)	Productivity (tons/metre)
2020	7.4	56,000	132.1
2021	7.9	62,000	127.4
2022	7.785	73,100*	106.5
2023	7.7	74,000	104.1
2024	7.486	70,970	105.5
2025	7.1	66,000	107.6

*Source: SOCAR audited consolidated financial statements (EY); Ministry of Energy of Azerbaijan and SOCAR press releases, 2020–2025. *2022 drilling volume is estimated, back-calculated from a reported year-on-year percentage change; the exact official figure was not identified in public sources.*

The SOCAR data tell a related but distinguishable story from the ACG data. Drilling productivity fell sharply and continuously from 132.1 tons per metre in 2020 to 104.1 tons per metre in 2023, a 21.2 percent decline in just three years, a faster rate of deterioration than ACG's capital efficiency measure over any comparable three-year window. Unlike the ACG series, however, SOCAR's productivity decline appears to have arrested, and even mildly reversed, over 2024–2025, settling in the 105–108 tons-per-metre range. Two explanations are consistent with the available data, and this article cannot distinguish between them without further field-level information: either SOCAR has introduced more efficient drilling technology or better-targeted well placement since 2023, genuinely improving productivity per metre drilled; or the 2024–2025 stabilization reflects a

compositional shift toward lower-decline, more predictable legacy reservoirs rather than a genuine efficiency gain, with the underlying maturation trend simply obscured rather than reversed. Resolving this ambiguity would require the same category of disaggregated, well-level data that BP publishes for ACG and that SOCAR does not currently publish for its own operations, a transparency gap discussed further in Section 8.

What can be stated with confidence is that SOCAR's own fields exhibit the same directional signature of maturation visible at ACG, declining output per unit of drilling or capital effort, even though the specific metric available to measure it (tons per metre drilled, rather than kbpd per dollar spent) is not identical, and even though the two entities' trajectories diverge somewhat in their most recent years.

7. Synthesis: Why Higher Prices Did Not Raise Revenue

The evidence assembled in Tables 1 through 4 supports a specific causal account of the anomaly identified in Section 4: Azerbaijan's oil-and-gas revenue continued to decline through the first half of 2026 despite a sharp rise in world oil prices because the productive base generating that revenue, both the BP-operated ACG block and SOCAR's own fields, has become measurably less efficient at converting capital and drilling effort into output, and this efficiency deterioration has, in the most recent period, outweighed the revenue-supporting effect of higher prices.

This is a structural explanation, not a cyclical one, and the distinction matters for how the finding should be interpreted going forward. A cyclical revenue shortfall, one driven purely by a temporary price dip, can be expected to self-correct once prices recover, as indeed the conventional price-and-volume model would predict. A structural shortfall, rooted in the underlying physical maturation of the reservoirs themselves, will not self-correct through price movements alone. Table 3's capital-efficiency trend and Table 4's drilling-productivity trend both describe processes, declining reservoir pressure, the exhaustion of the most accessible drilling targets, the rising well count required merely to offset natural decline, that operate independently of, and are not reversed by, the price of oil. Absent a change in the underlying productive base itself (through new discoveries, enhanced recovery technology, or a fundamental change in field management), Azerbaijan should expect future price increases to continue delivering a smaller revenue dividend than the same price increase would have delivered a decade ago, and future price *decreases* to compound an already-declining production trend rather than simply pass through proportionally.

8. Conclusion: Implications and Policy Recommendations

The productivity and capital-efficiency trends documented in this article are not merely descriptive curiosities; left unaddressed, they carry specific fiscal, commercial, and governance consequences, several of which are already visible in the H1 2023–2026 data examined above.

What the trend implies if it continues. First, and most immediately, Azerbaijan's state budget and SOFAZ transfer planning, both of which have historically been built around oil-price assumptions, will increasingly misstate expected revenue unless they are adjusted to account for capital-efficiency and drilling-productivity trends alongside price forecasts. The H1 2026 episode analyzed in this article is a direct illustration: a materially higher-than-planned oil price coincided with a revenue outcome that a price-only budget model would not have anticipated. Second, continued capital efficiency decline at ACG implies that an increasing share of the field's capital expenditure is being allocated not to growing production but to offsetting natural decline, a trajectory that, if it continues at the pace documented in Table 3, will eventually raise legitimate commercial questions about whether continued heavy capital investment in the field's most mature zones remains economically justified relative to alternative uses of that capital, including exploration elsewhere or investment in the energy transition. Third, SOCAR's drilling productivity decline, if it resumes after its apparent 2024–2025 pause, would compound fiscal pressure from a second, distinct source, one less subject to the disclosure and market discipline that BP's public reporting requirements impose on ACG. Fourth, and more broadly, both trends reinforce the structural case, made elsewhere in the literature on Azerbaijan's political economy, including in my own prior work (Ibadoglu 2008), for accelerating non-oil economic diversification: an oil sector that delivers a shrinking revenue dividend even in favorable price environments is a weaker foundation for long-term fiscal planning than official projections have historically assumed.

What should be done. Several responses follow directly from the analysis above.

On transparency and data governance. The single most actionable recommendation to emerge from this analysis concerns SOCAR's disclosure practices. The comparative difficulty of constructing Table 4 relative to Table 3 is not a methodological accident — it reflects a genuine and consequential asymmetry in what the two companies operating Azerbaijan's principal oil assets choose to disclose. BP's routine half-yearly publication of ACG's well count and capital expenditure enables the kind of efficiency analysis this article conducts; SOCAR's absence of comparable disclosure does not. SOCAR should adopt a standardized, periodic disclosure of well count and capital expenditure for its own upstream operations, disaggregated from its midstream, downstream, and international activities, comparable in format and frequency to BP's ACG reporting. Absent this, neither policymakers, independent researchers, nor the Azerbaijani public can adequately assess whether the country's second-largest oil producer is deploying capital efficiently — a governance gap that compounds the direct fiscal risk documented in this article.

On fiscal and budget planning. State budget and SOFAZ transfer-rule frameworks should be revised to incorporate a capital-efficiency-adjusted revenue projection alongside the

conventional price-and-volume forecast, so that episodes like H1 2026, a favorable price environment that nonetheless produces a revenue shortfall, are anticipated rather than discovered after the fact.

On field management and technology. For ACG, the sharp acceleration in capital efficiency decline between 2025 and 2026, a single-year deterioration larger than the change recorded across some multi-year intervals earlier in the series, warrants an independent technical and economic review of whether current well-development plans remain commercially optimal at this stage of field maturity, or whether a revised development strategy (for example, prioritizing infill drilling in the highest-remaining-pressure zones, or accelerating enhanced-recovery techniques) could improve the ratio of capital spent to output gained. For SOCAR, the 2024–2025 stabilization in drilling productivity should be investigated to determine whether it reflects genuine technological or operational improvement — in which case it merits documentation and wider application — or a temporary compositional effect that will reverse once the more favorable reservoirs currently being drilled are themselves depleted.

On long-term strategic planning. Both datasets point toward the same horizon: Azerbaijan's principal legacy oil assets are entering a phase in which sustaining, let alone growing, output will require steadily rising capital intensity. Planning for that trajectory, rather than continuing to treat oil-price recovery as a sufficient condition for fiscal recovery, is the central strategic implication of the analysis presented here.

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