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New Energy Sources for Jordan: Macroeconomic Impact and Policy Considerations

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Abstract

Jordan's initiatives to reduce its energy dependency could have substantial macroeconomic implications, but will crucially depend on the level of international oil prices in the next decade. Significant uncertainties remain regarding the feasibility of the initiatives and their potential fiscal costs, including from contingent liabilities, could be very large. Given the lead time required for such major investments, work should start now on: (i) conducting comprehensive cost-benefits analysis of these projects; (ii) addressing the challenges arising from the taxation of natural resources; and (iii) designing a fiscal framework to anchor fiscal policies if revenue from these energy projects materializes.

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I. INTRODUCTION

Several countries along the Southern and Eastern coast of the Mediterranean are net energy importers, and have experienced acute or rapidly rising energy dependency rates[1] in recent years. As a result, the import bill has widened and the fiscal burden due to subsidies has increased markedly.

Energy dependency (%)		
	2000	2011
Jordan	94.1	96.1
Lebanon	96.5	96.8
Egypt	-30.6	-13.6
Tunisia	9.2	20.7
Morocco	94.4	95.5
Source: WB database		

Energy imports (% of GDP)			
	2000	2010	2013
Jordan	7.5	11.6	16.2
Lebanon	7.1	12.0	10.3
Egypt	2.4	3.9	4.5
Tunisia	4.1	6.0	8.8
Morocco	5.5	9.0	11.7
Source: WEO			

Countries have started to tackle energy subsidies (see Sdralevich and others) and the recent decline in oil prices has provided some relief from high energy costs, but expectations are also rising about the availability of new energy sources in many countries in the region. This has been reflected in three parallel approaches being pursued by country authorities: (i) the advent of new fossil fuel sources (in particular, gas and oil shale); (ii) the progressive development of renewable energies; and (iii) the development of alternative infrastructure to access international energy markets.

Supply-side developments have gained particular attention in Jordan since disruptions in cheap gas imports from Egypt exposed the country's vulnerabilities in the energy sector. Jordan does not own proven and exploitable oil or gas reserves and the arid climate prevents reliance on hydro power.[2] Jordan needs to import not just crude oil, but also costly refined products because of the limited capacity of its only refinery. As energy demand grew steadily in recent years, reflecting both population and economic growth, energy imports increased from 9 percent of GDP in 2003 to almost 12 percent of GDP in 2010 (with a large share for electricity generation). When gas supplies from Egypt started fluctuating in 2011, Jordan had to resort to importing more expensive fuels, raising the energy bill further to 19 percent of GDP in 2012. Higher generation costs caused substantial losses for the national electricity company NEPCO, as end-user tariffs were kept unchanged.

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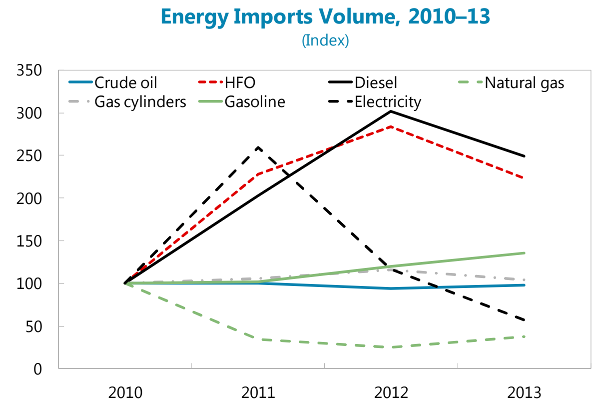
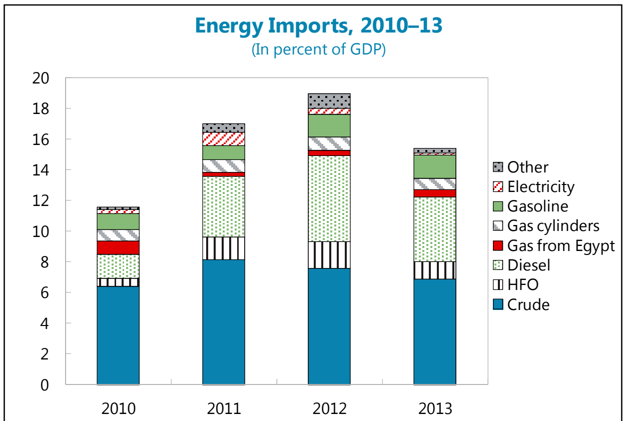
[1] Energy dependency is defined as the proportion of primary energy consumption which is imported. Country-level data are available at http://data.worldbank.org/indicator/EG.IMP.CONS.ZS/countries?display=default. A negative value, in tonnes of oil equivalent, implies the country is self-sufficient in terms of energy content (but could still be a net importer of energy from a BOP perspective).

[2] The only exception is a small gas field in Risha, which satisfies a minor share of Jordan's gas generation needs.

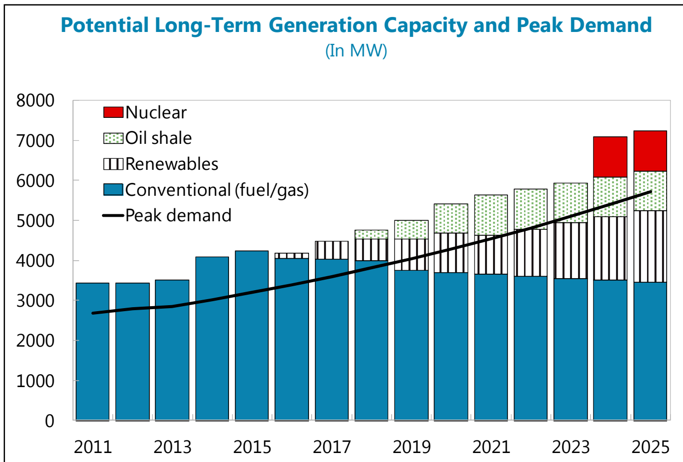


Sources: Central Bank of Jordan; and IMF staff estimates.



Source: Central Bank of Jordan.

To alleviate the fiscal and external pressure arising from high energy imports, various projects are moving forward or are being considered. Most of them are anchored in a medium-term energy strategy,[3] but all of them bear significant uncertainties, including from oil price volatility. These projects need careful cost-benefit and environmental analyses, and there are also important regional political considerations. Complementary infrastructure improvements (such as an upgrade of the refinery) may also be needed in order to make the investments commercially viable. With these caveats in mind, if soundly completed, these projects could substantially reduce Jordan's energy dependency and create significant fiscal benefits.



Source: NEPCO; Electricity Regulatory Commission; and IMF staff estimates.

This paper finds that the macroeconomic impact of these projects could be large, and that NEPCO would greatly benefit in the longer term provided oil prices stay on average above $50 per barrel in the next 10 years. However, the analysis needs to be refined once more details about the projects become available.[4] The paper also discusses several policy considerations. Perhaps most urgent is the need to rigorously evaluate the

[3] The strategy, available at http://www.memr.gov.jo/LinkClick.aspx?fileticket=PHxs463H8U0%3d&tabid=255, also contains measures to increase energy efficiency and anchors gradual tariff increases into a five-year horizon, targeting rich households and selected businesses, while protecting the poor.

[4] In particular, it will be critical to conduct an assessment of the Net Present Value (NPV) to the government of each project as soon as sufficient information is available. This should include any debt or debt-like obligations.

public private partnerships (PPP) which have been proposed to finance these projects. These contractual forms tend to reduce upfront costs, but often hide substantial future liabilities. The paper also calls for careful design of the contractual agreements with investors operating in the extractive industries. Finally, potential revenue streams from exhaustible resources (and any quantified costs or liabilities from PPPs) should be incorporated in an upgraded fiscal framework.

The paper is organized as follows: Section II sketches the main macroeconomic effects of new energy sources, showing results for alternative international oil price scenarios. Section III presents potential new import sources, including natural gas in both liquefied and gaseous state from international markets, and crude oil and gas from Iraq. Section IV reviews potential domestic sources of energy, including solar and wind power, shale, and nuclear energy. The last section summarizes the main findings and outlines policy considerations.

II. An Overview of the New Energy Sources and Their Macro Impact

The reforms and projects initiated by the Jordanian authorities will change the country's energy sector, reducing its energy dependence and diversifying its fuel mix. Specifically, a terminal in the port of Aqaba will allow Jordan to import Liquefied Natural Gas (LNG) from international markets, and further supplies of natural gas might be procured from the Eastern Mediterranean basin. Solar and wind farms have been fast-tracked and are expected to cover a significant share of electricity generation by 2020. Other long-term potential projects include: building a pipeline to pump Iraqi oil and gas to Aqaba for export and Jordanian consumption; exploiting oil shale resources; and a nuclear power plant.

Preliminary estimates show that the macroeconomic impact of the new sources will likely be large, but will crucially depend on the level of international oil prices in the next decade. However, any move away from the current fuel mix would benefit Jordan, unless oil prices remain extremely low for the medium and long term. More importantly, the relative desirability of the different new energy sources will depend on the level of oil prices. The energy strategy was conceived when Brent crude exceeded $105 per barrel ($/bbl), and the authorities have put emphasis on the lower cost-recovery tariffs guaranteed by technologies such as renewables, oil shale or nuclear. A large fall in oil prices, if sustained, would substantially reduce NEPCO's cost-recovery tariff (see Table 1). This would reduce the opportunity cost of switching away from traditional fossil fuels, and make some technologies almost cost-equivalent to traditional ones, at least in the short term. However, the new technologies do offer significant benefits in the longer term and most of them should certainly be pursued. Regarding few more controversial projects, it is necessary to assess carefully the cost-recovery level guaranteed by each project and to bear in mind non-monetary pros and cons before proceeding with implementation. This is in particular true for projects bearing significant upfront costs that would be incurred before starting operations, such as nuclear energy.

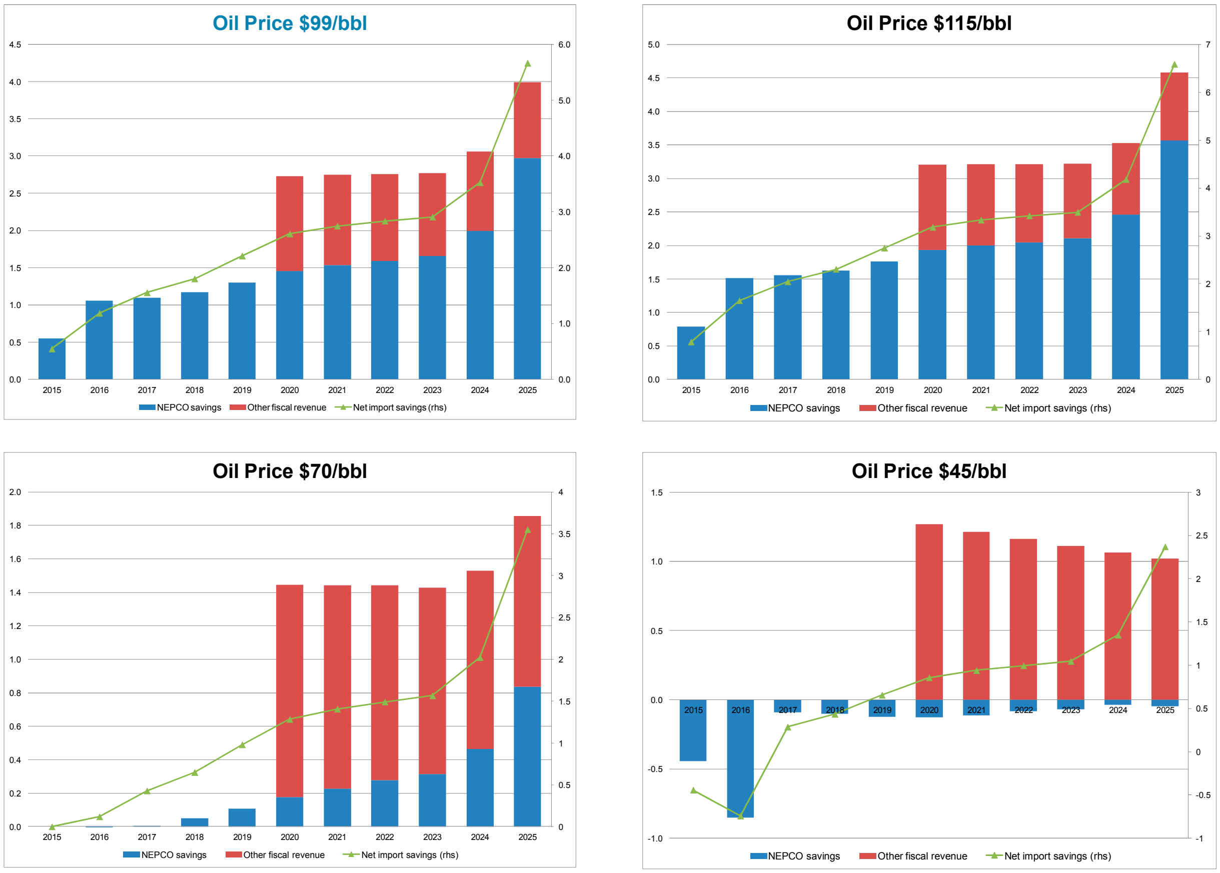
Table 1. NEPCO Cost Recovery Under Different International Oil Price Assumptions				
	$45/bbl	**$70/bbl**	**$99/bbl**	**$115/bbl**
NEPCO average cost (fils/kWh) 1/	87	116	153	169
1/ Computed as average cost-recovery bulk supply tariff assuming 2014 fuel mix. Estimate cost-recovery in 2014: 146 fils/kWh				

Figure 1 captures the findings of a preliminary quantitative assessment of ongoing projects, under different assumptions regarding oil prices throughout the study horizon (up to 2025). Fiscal savings (in the form of NEPCO savings) would be substantial with the advent of LNG and other technologies, provided oil prices stay above $70/bbl in the medium term. If prices approach $100, as was the case in 2014, savings will be in excess of 1 percent of GDP annually and could exceed 2 percent of GDP in the outer years. Conversely, if Brent prices stayed below $70/bbl, LNG might not be cost-competitive, but the terms of the supply contract could be adjusted once the initial supply period expires, eliminating the possibility of extra costs in the medium term. Renewable energies (and, to a lesser extent, oil shale) would still be a convenient alternative to traditional fuels. If prices stayed at about $45/bbl for the next 10 years, however, NEPCO would probably be better off holding on to conventional power plants for the medium term: while some of the solar power plants already in the pipeline would guarantee cheaper inputs to NEPCO than fossil fuels, it would take more than 10 years for these technologies to cover a share of generation capacity sufficient to ensure significant savings; most other technologies at the present stage would not be cost-competitive with oil prices at $50 or less. However, non-price considerations would still be a strong incentive to pursue most of these projects. For example, while renewable energies and oil shale may find price competition from traditional fuels, they would still greatly benefit the country's external position by reducing Jordan's large energy import bill.

Another potential source of fiscal revenues for Jordan comes from the oil pipeline from Iraq, and from the contractual arrangements with shale companies. Oil prices play an important role here as well. If completed, the transit fees for the oil pipeline will likely be based on volumes, but lower oil prices (in addition to security concerns) might delay–or even stop altogether–the completion of the pipeline. Similar concerns apply to shale producers, who might be deterred from new investment by tough price conditions; even if shale plants become operational, fiscal revenues associated with them are likely to get reduced if their output is sold at a lower price.

Figure 1. Jordan: Macroeconomic Impact of New Energy Source Under Different Oil Price Scenarios, 2015–25

(In percent of GDP)



Source: Author’s estimates based on NEPCO and Electricity Regulatory Commission data.
1/ For a list of projects included, please see Appendix 1.

III. New Import Sources

Natural gas

The construction of a LNG terminal in Aqaba will allow Jordan to import the equivalent of up to 400 million cubic feet per day (MMcf/d) of natural gas in gaseous state, resulting in a major turnaround of Jordan’s fuel mix for electricity generation by 2016. The terminal is expected to start operations at the latest in mid-2015. LNG will replace diesel and heavy fuel oil, which are more harmful to the environment and generally more expensive. Savings on electricity generation costs would depend on the co-evolution of oil and gas prices. LNG would probably become uneconomical if oil prices stay below $70/bbl for a prolonged period of time, but would rise quickly with any increase in oil prices. If 2014 price levels were sustained throughout the next decade, savings from LNG could exceed $400 million per year (1.3 percent of GDP), reducing both the import bill and NEPCO’s losses.

Table 2. Price Per Unit of Energy of Alternative Fuel Imports ($/MMBTU) Under Different International Oil Prices Assumptions

	$45/bbl	$70/bbl	$99/bbl	$115/bbl
Egyptian gas 1/	6	6	6	6
Diesel 2/	9	14	19	22
Heavy Fuel Oil 2/	8	11	16	18
LNG 3/	9-13	10-14	11-15	12-16
Gas from the Eastern Mediterranean 3/	6-7	6-7	8-10	8-10

1/ Based on negotiated contract
2/ Indicative.
3/ Range reflects lack of spot market; gas has not followed the recent decline in price of oil; final price to be negotiated.

Additional gas imports may become available from the Eastern Mediterranean basin (in particular, from two gas fields west of Israel).[5] Gas from the region would be cheaper than LNG because there would be no liquefaction and re-gasification costs. Abstracting from the political considerations surrounding this project (project discussion were recently interrupted because of tensions with Israel), savings for NEPCO and the current account from this project could range between $200-$600 million (0.6-2 percent of GDP) a year, depending on the price of traditional fuel alternatives.[6] Despite tensions at the government level, one individual contract has been signed by the potash industry for $500 million-worth of gas supply over 15 years. The quantity agreed by the potash company could reduce the import bill by as much as 0.3 percent of GDP per year, but would also imply some loss of revenue for NEPCO.[7]

Oil and gas pipeline from Iraq to Aqaba

Iraq and Jordan signed an agreement in mid-2013 on a pipeline from the Iraqi Basra fields to the Jordanian port of Aqaba. The contract for the construction of the Iraqi section of the pipeline had been awarded, but the security situation in Iraq will likely lead to major delays,

[5] There are a number of territorial or contractual disputes around gas fields in the region (in particular, some offshore fields in Gaza). The Leviathan and Tamar fields cited in this paper are not subject to territorial or contractual disputes. The Jordanian authorities are separately negotiating the potential supply of gas from both Palestinian and Cypriot fields.

[6] These estimates, which are very preliminary because no information about the price is available, are neither reported in Figure 1 or in the discussion of the total impact of new projects.

[7] The potash industry is paying an above-cost-recovery tariff, but would switch to self-generation when the gas from the Mediterranean basin becomes available.

and the paper assumes it will start operations before 2020. The Jordanian section is expected to be funded through a Build, Operate and Transfer (BOT) agreement with an international investor. The pipeline would initially carry up to one million barrel per day (bbl/d), of which around 150,000 bbl/d would be available for use inside Jordan (Energy Information Agency 2013). A natural gas pipeline would run along the same route, with up to 100 MMcf/d available for use in Jordan (sufficient to cover the generation of around 20 percent of Jordan's current electricity demand). The pipeline would substitute importing crude oil via tankers through Aqaba and truck delivery from Iraq.[8]

- The import bill could be reduced, as the market price of the Iraqi crude and gas are likely to be lower than the international price of Arab light and LNG. The actual savings will depend on international prices and whether there will be any discount on Jordanian imports.[9]

- Jordan is likely to receive a transit fee for the oil exported through Aqaba. Preliminary estimates based on agreements for existing pipelines in the region could indicate a revenue stream of up to $500 million (1.4 percent of GDP) per year. That said, even if transit fees are usually calculated in volumes, low oil prices for a prolonged period of time might lead to lower transit prices.

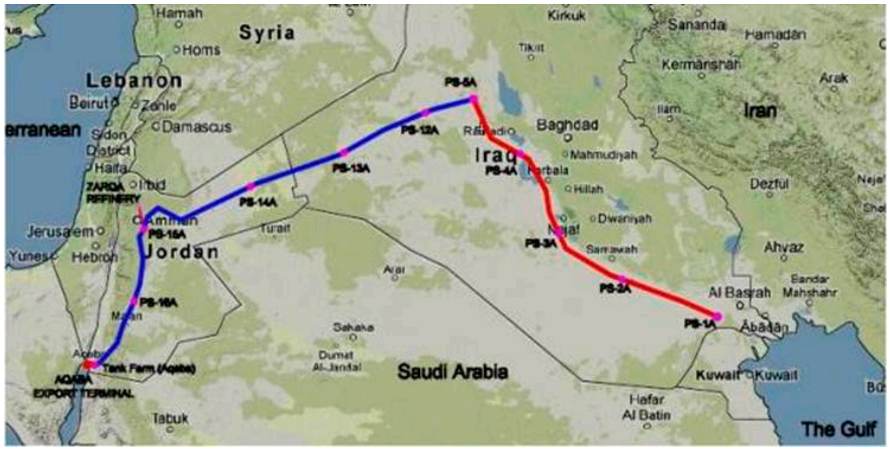
Jordan would not pay for the investment upfront, but might incur liabilities in the long term. The planned arrangement for the Jordanian section of the pipeline implies that the investor fully bears the construction and maintenance costs. Jordan would provide the "transit right," including land[10] and the right to perform maintenance, but would be expected to take over the operation of the pipeline (and the associated costs) in the distant future.

[8] The share of crude imports from Iraq is currently minor, but crude from Iraq comes at a significant discount granted by the Iraqi government.

[9] Due to the uncertainty of these savings, they are excluded from the total savings discussed in Section II.

[10] While no details are available, it is expected that any land acquisition costs related to the pipeline will be small.

Figure 2. The Planned Pipeline Between Basra and Aqaba



Source: Iraq Oil Authority.

Jordan's refinery needs an upgrade to handle additional oil. Currently, the refinery can process about 24,000 bbl/d, while the country's oil demand is above 100,000bbl/d. With potential imports of 150,000 bbl/d through the pipeline, a significant expansion and/or additional refineries would be needed.

Risks to this project are high. Even assuming the pipeline is completed, there could be disruptions to oil and gas supplies due to security or other operational problems. The magnitude and large uncertainties surrounding the projects imply several policy considerations:

First, the design of the BOT contract is critical. The investor is reportedly going to operate the pipeline for twenty years or more, before transferring ownership to the Jordanian government. At that time, operations and maintenance costs would be assessed by the three parties. The authorities will need to carefully examine the project at every stage of the investment process so as to not incur any unforeseen liabilities upon ownership transfer, with particular attention to any guarantees provided by the government. The design of the termination clause (including in the event of force-majeure or default by the private party) is also a critical consideration as it can affect the effective risk-sharing nature of the PPP.

Second, Jordan should review its fiscal framework. Albeit small by international standards, the transit fee from the oil pipeline would represent around 7 percent of 2013 domestic revenue. This means that the authorities will need to decide on what revenue share would be invested, saved, or used for debt repayments.[11] This decision will need to take into account

[11] See IMF, 2012a and 2012b for a discussion of fiscal regimes for extractive industries.

several factors, including that: (i) the resource underlying the pipeline revenue is exhaustible; (ii) Jordan faces large development needs; and (iii) there might be execution capacity constraints. To evaluate options, the authorities could use alternative fiscal benchmarks that take into account resource exhaustibility, such as the Permanent Income Hypothesis, and appropriate fiscal targets, such as a non-resource primary balance or the structural primary balance.[12]

Moreover, fiscal institutions need strengthening for an efficient and transparent use of the pipeline revenue. Proper accounting of revenue and of the underlying non-resource fiscal position is a prerequisite for sound fiscal planning. There should also be transparent mechanisms for all stages of the investment execution to ensure that revenue is used to support growth and equity in the most efficient manner. Finally, budget decisions should be based on the additional revenue only when it is assured that supplies are reliable and proceeds will materialize.

Transit revenue could be paid in kind or in cash. In-kind proceeds could be easily administered and provide an insurance against price changes. They should be eventually monetized through standard domestic taxation or tariffication, rather than earmarked to subsidize energy and electricity consumption (see Sdralevich and others, forthcoming). The in-kind option has been pursued, for example, by Georgia (Billmeier and others, 2004), but cashing in-kind fees could have drawbacks (for instance, because of volatility in consumption[13] or poor payment discipline).

Finally, the completion of the pipeline would bring to the fore a structural bottleneck in Jordan's energy sector. The only domestic refinery would need an upgrade to process the crude imported from Iraq. The privately-owned refinery has long enjoyed a monopoly power and regulated profits. Since the revamp is needed anyway, as the hardware is old and unable to cope with domestic demand,[14] it would be advisable that the private sector be in charge of the upgrade. The cost is estimated at about $1.5 billion.[15]

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[12] See Baunsgaard and others, 2012.

[13] This issue is of concern in countries where demand is unable to absorb the volume of in-kind supply. Given Jordan's energy needs, it is unlikely to be a problem.

[14] Also, the Iraqi oil is of lower quality and refining it might require additional improvements and additives.

[15] The authorities could consider liberalizing the market and promoting the construction of new refineries as an alternative. However, the small size of the Jordanian market might deter investors.

IV. New Domestic Energy Sources

Renewable energies

The authorities' energy strategy forecasts renewable energy generation to cover one-fifth of Jordan's energy demand by 2020. In the course of the last year, two separate calls for expression of interest have been launched for the construction of solar and wind farms. The authorities have introduced a "fast track" to streamline procedures and evaluated and pre-selected bidders under a framework agreement that included a pre-determined feed-in tariff (i.e., the tariff on which the new power plants will sell electricity to NEPCO).

The current account would improve, but NEPCO's losses would decrease only marginally at first. Import savings could reach about one percent of GDP per year by 2020. NEPCO's savings would increase as the share of renewable energy in total generation expands. The feed-in tariff is reported to be capped at JD 0.12 per kWh for projects pertaining to the first round of investments, and at JD 0.08–0.10 for subsequent rounds (the 2014 average unit cost of electricity purchased by NEPCO was about JD 0.146, see Table 1).

From a policy perspective, the financial conditions of the Power Purchase Agreements (PPA) should be set carefully. NEPCO is de facto making a long-term commitment to buy all electricity generated by renewable energies[16] at a price being negotiated now. Thus, the feed-in tariff should take into account the long-term evolution of actual and opportunity costs, so as to avoid any unexpected liabilities of the government, including foregone savings from the evolution of prices of other fuels. The recent fall in oil prices is a useful example. If the international prices prevailing in January 2015 were sustained, the first wave of renewable energy projects (whose feed-in tariff is already set at JD 0.12) would sell electricity at a higher price than conventional power plants. That said, several investments are expected to be completed in the next three years, with the conditions set out in the tenders attracting strong interest but also providing for a lower feed-in tariff, which would guarantee savings compared to conventional sources even in the face of exceptionally low oil prices for a prolonged period of time. Going forward, any unilateral changes on signed contracts should be avoided and rather be sought through a negotiated solution.[17]

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[16] Given current peak load and generation capacity, it is unlikely that there is insufficient electricity demand in the future to sustain NEPCO's purchases. However, additional costs might arise for NEPCO related to the change in the use of conventional power plants. This is because a large share of renewable energies in total electricity supply usually leads to less than full capacity utilization of conventional power plants during daytime hours.

[17] While unilateral changes in contracts by the government scare investors away and can have significant medium-term repercussions, renegotiations are quite common in PPAs after a few years of project implementation. The renegotiated conditions, in the majority of cases, favor the investor rather than governments, but it is uncommon for contracts to be completely cancelled (Jin, 2013).

Also, the grid needs upgrading. It is expected that the grid will have to cope with up to 1.8 GW additional generation capacity from renewable energies in the next ten years. The network can accommodate the first round of new plants coming online, but in the next few years grid connection capacity is likely to become a constraint to renewable energy development.[18] Significant infrastructure investments will be needed to transmit power from the south (where solar farms will be concentrated) to Amman and the north (where energy demand is most intense). The necessary improvements could cost around $150 million (0.5 percent of GDP) and would be spread over three years during 2014–16.[19]

Oil shale and shale oil

Jordan's proven reserves of oil shale are amongst the largest in the world. Shale formations allow both for the use of oil shale directly in power plants and for the extraction of synthetic crude (shale oil) from the rocks through a chemical process.[20] However, the viability of most of the reserves is still under study. Several explorations are under way.

The first oil shale power plant is to start operations by 2018. The authorities have signed a Build Own and Operate (BOO) contract with a foreign investor. The eventual cost for Jordan will be in the form of an "average tariff"[21] that NEPCO will pay to the generator through a Power Purchase Agreement.

Commercial exploitation of shale oil could start toward the end of the decade. Two concessions are under consideration to extract shale oil via surface retorting and a longer-term project might exploit deep-seated oil shale. The eventual size and output of these projects are uncertain.

External and fiscal accounts would improve, with significant upward potential from shale oil exploitation.

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[18] A third round of expression of interest for a total 800MW capacity will take place only after the network has been upgraded.

[19] These and other projects are part of the so called "Green Corridor," specifically designed to support the network when renewable energies come online. Several donors are active in the energy sector and some have expressed interest in funding such investments.

[20] Technically, oil shale is a rock that can be burned directly in power plant furnaces to generate electricity. Alternatively, liquid shale oil can be obtained from the combustion of oil shale. Shale oil can be used as low-grade fuel or upgraded to standards close to conventional crude oil for use in refineries.

[21] The agreements for the construction and operations of oil shale plants differ from those for the operation of renewable generation. NEPCO is not committing to buy all generated electricity in advance, but will pay a variable "capacity charge," which will be a function of actual purchases, on top of the "average/leveled tariff." The latter will guarantee that the investor can recover fixed investment costs.

- Preliminary estimates put oil shale tariffs at around two thirds of the current cost-recovery tariff. Oil shale will be a competitive alternative to traditional fuels, provided Brent oil prices stay above $50/bbl on average for the next 10 years. The first plant would produce 230 MW (compared with a peak demand at over 3,000 MW by 2018). As additional capacity is added, NEPCO would save as much as $130 million a year (0.2 percent of 2020 GDP) and the import bill would be lowered by a larger amount (up to $500 million per year), because imports are fully substituted with domestically-sourced fuel.

- Any successful exploitation of shale oil could yield large additional current account benefits as well as fiscal revenue, but this currently cannot be quantified. Refining upgraded shale oil in Jordan for domestic consumption and even export could yield further benefits.

On the other hand, contingent liabilities of oil-shale power generation could be large. As in the case of renewable energies, any PPA needs to strike a balance between making the investment attractive and providing significant benefits to the public sector. In the case of oil shale exploitation, though, environmental issues could lead to potentially large public liabilities, which need to be carefully analyzed.

Importantly, the full fiscal implication of the PPP should be incorporated in the fiscal framework.[22] The BOO contract is equivalent in many ways to traditional public procurement with debt financing. As such, the choice of PPPs over traditional public investment should be done purely on the basis of what investment form provides the highest value for money to the government. The obligations arising from the PPPs should be included in the medium-term fiscal framework and in the debt sustainability analyses.

Fiscal policy implications of shale oil exploitation could be major. If commercial exploitation is viable, not only should the fiscal framework be reconsidered (see also the section on the oil pipeline), but there is also a need to develop an appropriate taxation regime. A balance would be needed between maximizing fiscal revenue and minimizing its volatility, maintaining an adequate remuneration for investors, and keeping the administration of the chosen regime as simple as possible. Contract stability should be ensured to the extent possible, as this is an important factor attracting investors (in particular if additional explorations are possible).

Details of the taxation regimes can have a large impact on projected revenues. Usually, a large portion of total revenue from extraction accrues to the state, either in the form of a royalty, a rent tax, a production sharing agreement, or a service contract type of payment. These arrangements can sometimes be used in combination, bearing in mind that ease of

[22] To ensure transparency, the project value of all PPPs should be recorded as on-budget public investment (consistent with accounting guidance of IPSAS 32).

administration is paramount. As shown in Daniel (2010), the details of each regime (in the form of depreciation rules, royalty rates and basis, government equity participation, and the presence of other “conventional” taxes such as VAT or corporate tax) can change substantially the government’s share of economic benefits accruing from the exploitation project.

A major caveat stems from the large amounts of water required for shale oil exploitation. Given Jordan’s water scarcity, there is a need for promoting water-saving technologies, including in electricity generation. As such, the direct monetary costs of water supplies to shale oil projects, even if charged well above cost recovery, could underestimate the costs of foregone water in the future.

Also, investment in logistical infrastructure needs to be factored in, and careful planning should avoid port congestion in Aqaba. If all the ventures described above are fully realized, Aqaba could become a hub for fuel trade in the Eastern Mediterranean. Tankers will bring in LNG for imports, crude from Iraq for exports and potentially shale oil distilled within Jordan for upgrade and or refinement abroad. Given the small and environmentally delicate area of the port of Aqaba, any energy project requiring a port expansion needs to fully take into account the associated costs and environmental risks, together with any potential repercussion on tourism.

Nuclear power

Jordan has long been considering nuclear power. Driven by the prospect of extracting uranium, the authorities have developed a strategy to build two nuclear reactors generating 1,000 MW each in the next decade. They have already selected a preferred bidder that will conduct further studies and risk assessments; negotiations on the final contract would possibly start within two years.

There would be substantial investment costs for the government. Construction would require an investment of about $10 billion, including grid improvements. The foreign operator would bear about half of the cost, and the Jordanian government would retain 51 percent of equity in the joint venture, of which 25 percent would be immediately sold to a third-party investor. All design, construction and maintenance costs will be subsumed in the feed-in tariff the government would commit to pay in exchange for an agreed amount of generated electricity for up to 60 years.

Current account and fiscal savings could be substantial. The cost per kilowatt of electricity generated by a nuclear plant could be as low as half of current NEPCO unit costs. Savings could amount to up to $300 million a year (1 percent of 2014 GDP) for the external account and about $150 million for NEPCO, but only half of the yearly savings will materialize by 2025, as the second reactor will be built only after completion of the first. If the uranium needed for the reactors is sourced in Jordan,[23] current account and fiscal savings could be higher; on the other hand, if oil prices remain at low levels, savings compared to traditional fuels could be halved, and the authorities should keep oil price fluctuations in mind when finalizing their cost-benefit analysis.

Most importantly, though, environmental and safety risks could be enormous. While the average unit cost of electricity generated by a nuclear plant may be attractive, there are significant implicit liabilities that should be priced in. Typical issues are an over-estimation of future electricity demand and under-estimation of the costs associated with waste disposal, force majeure, and decommissioning of the plant at the end of its life-cycle. Also, it is important to bear in mind that it is usually difficult for the public authority to completely step back from a PPP turned sour, once the project has started (see footnote 22).

It is also worth noting that, as with the shale oil projects, a nuclear plant requires large amounts of water. The authorities are planning to cool the plant with waste water to minimize the impact on Jordan's scarce fresh-water deposits. Such a solution is likely to increase costs and requires a close proximity of the plants to urban centers, thereby further increasing the need of a careful safety assessment.

Finally, the large upfront costs would substantially increase public debt. Current estimates put the share of costs to be borne by the public sector at well over 10 percent of 2013 GDP. Further debt-like obligations might arise if costs increase, and these should also be appropriately reported in the fiscal accounts. In this context, consideration should also be given to alternative smaller projects, including in renewable energies, which would not require direct government involvement. To spur this process, small power plants could be allowed to sell directly to the private sector, rather than to NEPCO.[24]

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[23] Discussions are under way to mine the uranium in Jordan, enrich it in a third country, and import it back for use in the reactors.

[24] Such projects would call for a rethinking of Jordan's electricity market model, as NEPCO is by law the single buyer of electricity from generators. Exiting from the single buyer model would put Jordan in line with best practices and bring the energy sector reform started in the early 2000s to a completion.

V. Conclusions and Policy Recommendations

Many of the projects reviewed in this paper have the potential to become a deal changer for Jordan, promising either substantial savings or a significant revenue stream. Quantification is difficult though, and the prevailing level of international oil prices will play a key role in determining how these new sources should be dealt with or sequenced in. Total annual fiscal savings could range between less than 1 to about 4 percent of GDP, depending on oil price levels, and import savings could reach about 5 percent of GDP provided all announced projects are implemented. However, contingent liabilities could be large, but they are impossible to quantify at this stage. The paper identifies three specific areas where policy action is needed to ensure the opportunities provided by the new energies materialize into real benefits for the Jordanian citizens.

First, the unconditional choice of PPPs as the contractual form to implement energy projects should be reassessed. International experience has shown that typically, PPP contracts bear significant, and often unforeseen, long-term liabilities for the public sector. A framework for the evaluation and management of PPPs should be established, with a central role for the ministry of finance. The focus should be on the assessment of all known and implicit costs and their impact on the fiscal accounts. Also, financial and economic cost-benefit analyses should be employed (World Bank, 2013) to inform the choice between PPPs and other forms of traditional public financing. To ensure transparency, the project value of all PPPs should be recorded as on-budget public investment.

Second, the appropriate taxation regime for natural resource extraction should be considered as contractual frameworks need to be prepared soon. Looking at other country experiences would help find the right balance between keeping investments attractive and maximizing the benefits to Jordan.

Finally, the fiscal framework should be revised in view of the potential revenue streams from the pipeline and the shale oil. The first step would be to identify an appropriate fiscal anchor to inform decisions on how much to spend or save of the resource-related revenue, taking into account the high uncertainty of the future revenue stream. Long-term contingent liabilities, once properly quantified, need to be factored in. Fiscal institutions also need to be strengthened to transparently report additional revenue and its uses.

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Annex—Assumptions and Methodology for Estimating the Macroeconomic Impact of New Energy Sources

Most of the calculations rely on industry standards and qualitative considerations related to the specific Jordanian case. They also used information reported by the media and publicly disclosed agreements.

Table 2 on page 7 reports the assumptions on the fuel mix for electricity generation during 2015–25. NEPCO savings from the introduction of each alternative source are computed by multiplying its assumed share in generation capacity by the difference between the 2015 bulk supply tariff (computed assuming the same fuel mix of 2014 and at different oil price levels, and reported in Table 1) and the feed-in tariffs expected to be paid to non-conventional generators in the coming years (see text table below). Savings from LNG are obtained directly from NEPCO's estimation of how its fuel mix would change as more or less gas becomes available in 2015.

Cost recovery tariff and feed in tariff assumptions, JD fils per kW

	Oil price assumption			
	$45	**$70**	**$99**	**$115**
Cost recovery bulk supply tariff 2015 1/	87	116	153	169
Feed in tariff renewables - 1st phase	120	120	120	120
Feed in tariff renewables - 2nd phase wind	100	100	100	100
Feed in tariff renewables - 2nd phase solar	80	80	80	80
Feed in tariff oil shale	100	100	100	100
Feed in tariff nuclear	80	80	80	80

1/ Assuming same fuel mix as 2014; estimate cost recovery tariff in 2014: 146

Import cost savings equal generation costs savings for LNG and gas imports. For domestic sources such as renewable energies, oil shale and nuclear, complete import substitution is assumed: for each new technology, import savings equal the value of fuel imports NEPCO would be required to purchase in order to generate as much electricity with the current generation mix.

The model has the following further assumptions:

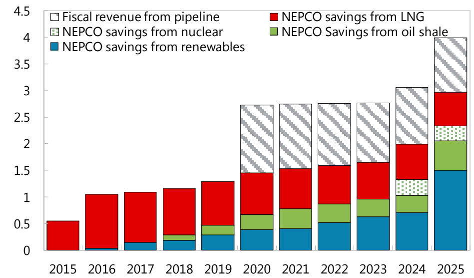
- Revenue from the Basra-Aqaba pipeline is $1.5/bbl, in line with recent similar transit contracts signed in the region.
- The construction cost of the nuclear plant to be paid by the government is JD2.5 billion over 5 years, and it is financed through debt issuance with an interest of 7 percent.

Annex Table 1 below reports preliminary estimates of the breakdown of the macro impact of proposed new energy by project, under a variety of oil price scenarios.

Annex Table 1. Fiscal and Import Savings of New Energies Under Different Oil Price Assumptions, 2015–25

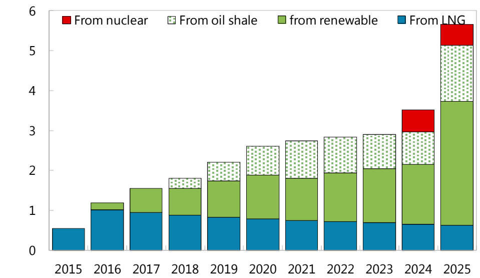
Oil prices at $99/bbl throughout the projections horizon

Fiscal Saving, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

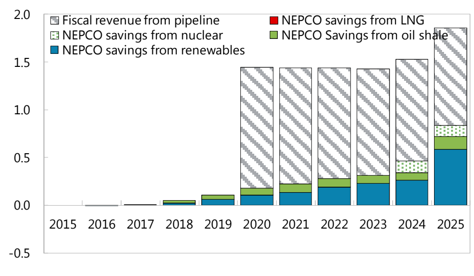
Import Savings, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

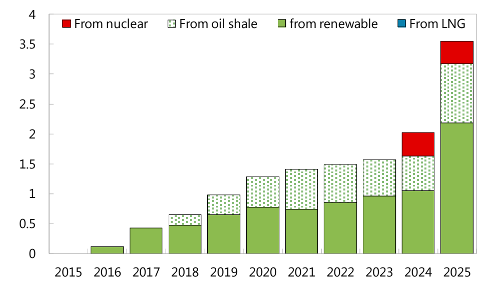
Oil prices at $70/bbl throughout the projections horizon

Fiscal Saving, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

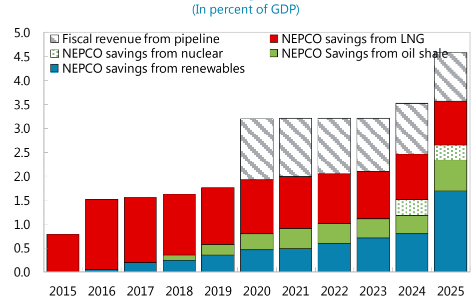
Import Savings, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

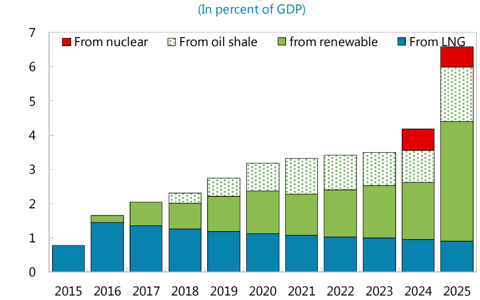
Oil prices at $115/bbl throughout the projections horizon

Fiscal Saving, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

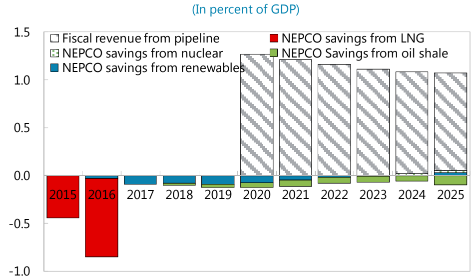
Import Savings, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

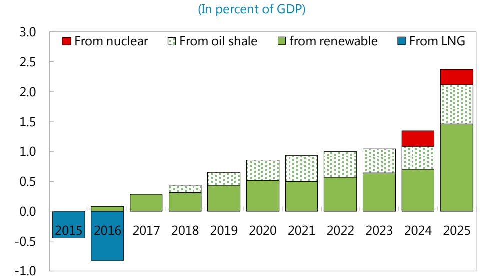
Oil prices at $45/bbl throughout the projections horizon

Fiscal Saving, 2015–25
(In percent of GDP)



Source: IMF staff calculations.

Import Savings, 2015–25
(In percent of GDP)



Source: IMF staff calculations.