Environmental Risks of Condensate Releases - Leviathan Offshore Gas Project, Israel

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Background

1. It is evident that Leviathan proponents (industry and government) have dedicated an impressive amount of time, effort, and financial resources in planning and development of the project to date. The reviewed documents present a thorough background of the baseline regional environment, a basic description of the project, and reasonable assessment of *some* of the expected construction and operational impacts.

2. It is noted that the Leviathan development is considerably advanced at present, with several wells having been drilled and completed. Thus the comments below may have been more useful to project planners and the Government of Israel if provided earlier in the process. Nevertheless, the comments and concerns outlined in this report remain relevant for all aspects of the project. Even at this stage of project development, it is hoped that this report may help improve the environmental safety of the project.

3. The documents reviewed are insufficient upon which to conclude that the Leviathan project meets its safety declarations and objectives and best industry practice. Significantly, documents understate the risks and impacts of the Leviathan project from a potential catastrophic failure of any of the several systems-critical project components, and overstate response capabilities. The documents fail to account for the many ways in which a complex system such as a deepwater gas project can fail, causing a low probability/high consequence event such as a major gas/condensate well blowout or pipeline release. In the post-*Deepwater Horizon* understanding of deepwater drilling risks, this is unacceptable. While impacts from construction and normal operation of the project may be moderate as predicted, impacts of major failures could be catastrophic. These catastrophic risks have not been adequately assessed.

4. The Leviathan documents reviewed are poorly integrated, redundant, often inconsistent, contain significant errors (e.g. units of measurement), contain significant gaps in essential information, and often make vague and general assertions lacking detail. This poor organization of documents makes it

difficult for the public to assimilate project information and reasonably evaluate environmental impacts and risks of the project.

5. The current status of Leviathan development and permitting remains unclear to the author. The project schedule reported in the 2016 Drilling EIA states that offshore well drilling and completion would be underway at this time. Yet, there is much detail on this and other aspects of the project that were unavailable to the author, including any Applications for Permits to Drill (APD). This presented a significant handicap to a comprehensive review of the project.

Spill Modeling

6. Condensate is a light, volatile, and acutely toxic petroleum hydrocarbon mixture that behaves very differently than heavier crude oil when released into the marine environment. Condensate releases generally do not form definable surface slicks (as do crude oils), and thus condensate spills are not amenable to traditional spill response methodologies. While not as persistent as crude oil when released into the environment, condensates can persist for well over 6 months once released. In addition, weathered condensate is known to be even more acutely toxic than fresh condensate, down to concentrations as low as 0.04 ppm (40 ppb).

7. The condensate spill models conducted for Leviathan (OSCAR and MEDSLIK) are robust and useful, but fail to model true Worst Case Discharges from each project component, ignore water column entrainment, understate potential impacts, and overstate response capability to mitigate such impacts.

8. For the Drilling phase, MEDSLIK modeled a wellhead condensate release of 857 m3 (5,827 bbls)/day x 30 days (this data was redacted, but retrievable), for a total release of 25,110 m3, or about 175,000 barrels (bbls). Given the history of deepwater petroleum blowouts, this is clearly not a Worst Case Discharge. The project should model a blowout at this rate continuing for at least twice this length of time (60 days), for an approximate condensate release volume of 350,000 bbls.

9. By comparison, the failed Macondo oil/gas well drilled by the *Deepwater Horizon* in 2010 in the U.S. Gulf of Mexico, at comparable depth and pressure to Leviathan, released an average of 62,000 bbls/day of oil over 87 days, for a total oil release of 4.9 million bbls (oil equivalent). And the 2009 Montara oil/gas platform blowout off northwest Australia (in only 76 m water depth) continued for 74 days. Accordingly, the 30-day well blowout period modeled for Leviathan is insufficient, and should be increased to at least 60 days.

10. For the Production (seabed pipeline) phase, the modeled Worst Case Discharge was approx. 1,220 bbls – 1,320 (194 m3) bbls condensate, based

on the release of total pipeline inventory, plus 5 minutes response time to shut-in the pipeline. This represents an underestimate of potential Worst Case Discharge volume, and should be revised upward. This underestimate derives from the assumption that a pipeline failure will be immediately detected and shut-in with proper functioning of the Surface Controlled Sub Surface Valve (SCSSV) system from the Leviathan Production Platform. However, there is no discussion of a contingency for the failure in this surface-controlled system (e.g. severed umbilical connection, fire/explosion on the LPP, etc.), which could lead to a much larger release of gas and condensate from seabed pipelines.

11. For the near shore Leviathan Production Platform (LPP), the OSCAR model assumes a release of only 1,000 bbls condensate, while OSCAR also models a very small condensate release (from a dropped object), of only 15.9 bbls of condensate and 75 tons of gas. MEDSLIK also modeled a 100,000 bbls condensate release from a Floating Storage and Offloading (FSO) tanker/facility (NOP 37/H Guidelines), which was not selected for the final Leviathan design. At minimum, a release of the entire storage capacity of approx. 5,000 bbls of condensate from the LPP should be modeled. Both models assume approx. 40%-50% evaporation of condensate, with the remaining balance dispersing in the marine environment and/or beaching on shorelines. Both models predict substantial shoreline contamination from a Worst Case Discharge condensate release at the LPP.

12. Surprisingly, the Leviathan documents do not discuss in detail the potential large-scale release of natural gas from failure of subsea infrastructure, its potential fate, or ecological impacts. In addition to releasing 350,000 bbls of condensate, a Worst Case Discharge from a failed deepwater well could also release perhaps 100,000 tons of natural gas into the deep ocean ecosystem off Israel. Natural gas (99% methane) is known to be toxic to marine organisms, particularly at warmer water temperatures (and higher metabolic rates in organisms) found off the coast of Israel. The lack of detailed evaluation of a large gas release is a significant gap in the environmental assessment of the project.

13. Regarding ecological impacts of condensate releases, the documents assert that: "*No High risk impacts were identified in the evaluation from routine activities or accidental events.*" This is not supportable. If as modeled, 175,000 bbls of condensate is released from a Leviathan deepwater well failure, spreads over 395,000 km2 of coastal ocean, results in water hydrocarbon concentrations in excess of 300 ppm, persists for months, and contaminates 388 km of shorelines from Egypt to Syria with over 88,000 barrels of toxic weathered condensate; then clearly the ecological impacts would be "high", not "moderate" as predicted by the EIAs. If a Worst Case Discharge of twice this much or larger occurs, then impacts would be correspondingly greater.

14. The EIAs do not sufficiently discuss the potential for *long-term* ecological impacts from a major offshore gas/condensate release.

Mitigation/Spill Prevention

15. Mitigation/spill prevention is poorly developed in the documents. As this is the most critical aspect of environmental risk reduction, this needs considerably more technical detail. For instance, the documents do not present a clear plan for preventing well blowouts or seabed pipeline failure, robust well design and control, pipeline design, pipeline Integrity Management (IM) program, pipeline Leak Detection, personnel training, third party services, management of change, near-casualty reporting and investigation, risk assessment, subcontractor management, and equipment maintenance and surveillance. Although several deepwater gas wells have been successfully drilled off Israel in recent years with no reported major hydrocarbon release, any of the next wells drilled could fail catastrophically. Prior to the 2010 *Deepwater Horizon* oil/gas blowout in the U.S. Gulf of Mexico, hundreds of deepwater wells had been drilled, most with no well-control incident. The Leviathan documents project a troubling sense of complacency about this very real risk.

16. Risk is inherent in all offshore oil and gas projects, and cannot be reduced to zero. But as even simple failures in complex industrial systems such as Leviathan can lead to catastrophic consequences for the environment and public safety, the government must require that the highest risk reduction standards are employed for the project. But as Leviathan commits only to a risk reduction standard of *As Low As Reasonably Practicable* (ALARP), this is *prima facie* evidence that the project may not always employ *Best Available Techniques and Technology* (BAT), such as in instances where BAT is judged too costly or otherwise not "reasonably practicable." As example, *Produced Water Reinjection* (PWRI) is widely recognized as BAT, but was declined for Leviathan due to cost. The Leviathan project must be required to commit to BAT at all times, regardless of cost, and employ a risk reduction standard of *As Far As Possible* (AFAP), as is best industry practice, and is required in the E.U. offshore drilling rule.

17. A considerable amount of systems-critical information (as referenced above) is simply redacted from documents. This is highly unusual, and for a project with such potential consequence and public interest, is unacceptable.

18. The 2011 Leviathan 2 blowout is mentioned briefly in the Drilling EIA, but insufficient detail is provided. As a result of this loss of well control incident, the drill rig disconnected from the well, and formation waters/brine flowed from the failed well from May 2011 – Sept. 2012 (16 months) before being plugged. This is an unacceptable response to a well control incident, and

calls into question the veracity of many of the well control assertions made in the documents. Benthic impacts from this incident reportedly continued for at least five (5) years. It is not known whether this failure was widely and accurately reported to the Israeli public, government, or lenders, but clearly it should have been investigated in detail, and transparently reported.

19. The project does not present a *Critical Operations and Curtailment Plan* (COCP), *Blowout Prevention and Response Plan*, drilling mud and cement formulations, and safety systems (e.g. gas alarms) on drilling rigs to be used (which had yet to be identified in the documents reviewed).

20. While Noble commits to meet U.S. and global best practice standards, the documents do not itemize the international standards and regulations the company commits to meet, which should include specific reference to all those of the U.S. *Bureau of Safety and Environmental Enforcement* (BSEE), *American Petroleum Institute* (API), *American Society of Mechanical Engineers* (AMSE), *American National Standards Institute* (ANSI), *Office of Pipeline Safety*, *Transportation Security Administration*, and the European Union's *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations.*

21. Documents do not identify well-control contractors that would be called upon to intervene in a loss of well control.

22. Documents do not detail a relief well contingency plan, whereby a relief well would be drilled from another rig to intersect and bottom-kill a well blowout.

23. Documents do not provide adequate detail regarding the Surface Controlled Sub Surface Valves (SCSSVs), and contingencies for failure of connection with surface control systems.

24. Pipeline *Integrity Management* and *Leak Detection Systems* are inadequately detailed in the documents. Petroleum companies operating in Israel must be required to comply with international best practice standards, including those of the *American Petroleum Institute* (API), and the *American Society of Mechanical Engineers* (ASME). Under U.S. regulation, a *High Consequence Area* (HCA) for pipeline operation is defined as any area with significant human population, navigable waterways, or an environment unusually sensitive to spills. It is recommended here that the Israel offshore and onshore regions be considered a *High Consequence Area* (HCA), requiring the highest BAT standards for all petroleum infrastructure, including well and pipeline design features, pipe wall thickness, pipe spacing, corrosion protection, inspection, maintenance, etc.

25. The Government of Israel should commission a comprehensive third-party *Integrity Management* (IM) assessment of all existing and planned gas and condensate infrastructure in Israel, offshore and onshore; and it should

require a rigorous, continuous IM program for all petroleum infrastructure. This IM assessment should be conducted on all planned offshore gas development, including Leviathan, Aphrodite Block 12, Dalit, Karish and Tanin, Daniel East and West; and existing developments including Tamar, Mari-B and Noa, Hadera Deepwater LNG terminal, Shimshon Gas Field, and Aphrodite/Ishai. As well, all onshore petroleum infrastructure should submit to such a comprehensive IM assessment.

26. The frequency of underwater *Remotely Operated Vehicle* (ROV) surveys on seabed infrastructure should be increased from annually, as currently planned, to at least monthly.

27. It is not clear that fire and explosion risk on the Leviathan Production Platform has been adequately assessed and mitigated via *Front End Engineering Design* (FEED). Explosion/fire on the LPP is a significant risk that could result in catastrophic consequences for human safety and the near shore environment. This must be further clarified.

Platform vs. FPSO or FLNG

28. The overall design selected for Leviathan eliminated options for offshore *Floating Production, Storage, and Offloading* (FPSO), or *Floating Liquefied Natural Gas* (FLNG), in use elsewhere in the world, without adequate consideration. An FLNG facility 125 km offshore, shipping LNG via shuttle tankers, would eliminate most near shore risks and impacts inherent in the current project design, which incorporates hundreds of km of seabed pipelines and a platform 10 km offshore. And an FPSO, also 125 km offshore, even with seabed pipelines transporting gas to shore, would also eliminate the substantial risks posed by the near shore platform. In evaluating all design options for the project (including an entirely offshore option), the documents claim: "*There were no significant environmental differentiators or showstoppers identified across all of the viable options*." This is categorically incorrect, as the offshore FPSO or FLNG option would significantly reduce or eliminate risks and impacts to the continental shelf environment and coastal public safety. Accordingly, the current project should be suspended and the FLNG or FPSO option reconsidered and adopted.

29. Regarding the relative environmental benefit of FLNG vs. onshore/ near shore processing (as currently planned in Leviathan), Royal Dutch Shell stated with regard to its Prelude FLNG project off the coast of Australia:

> *"FLNG technology offers countries a more environmentally-sensitive way to develop natural gas resources. Prelude will have a much smaller environmental footprint than land-based LNG plants, which require major infrastructure works. It also eliminates the need for long pipelines to land."*

30. And, Energean's 2017 *Karish and Tanin Field Development Plan* concludes that an FPSO option offers several advantages over the onshore/nearshore processing option, including: an FPSO minimizes work necessary in the field, quicker development time, capital expenditure considerations, increased opportunities to export, tie-back of multiple 3rd party fields, reduced technical risk (e.g. hydrate formation in seabed pipelines), enhanced product recovery from field, ease of abandonment after field is exhausted, and *significantly reduced environmental footprint*. Even with seabed pipelines transporting dry gas to shore, an FPSO is clearly a safer option for the near shore and coastal environment. Noble should explore leasing an FPSO for initial Leviathan development, to tie-in to the seabed pipeline infrastructure transporting gas to shore and into the INGL system.

31. Regarding relative security risks of a platform vs. FPSO/FLNG facility, a former Noble Energy official stated as follows to a 2011 Tel Aviv conference:

    "*Planning a terrorist attack on an unprotected oil platform is as simple as chartering boats, training divers, and providing them with the explosives required. Options to reduce risk and maximize flexibility could include using a floating platform capable of processing gas into LNG. All security efforts would be concentrated at the drilling platform and FLNG facility, thereby reducing other, greater risks in natural gas production and transportation."*

Spill Response

32. The Leviathan documents overstate the capability to respond to (contain/recover) an offshore condensate release. It is generally accepted in the international spill response community that there exists no containment/recovery methodology that would be effective for offshore condensate (or natural gas) releases. The Technical Lead for *Oil Spill Response Limited* (OSRL) in the UK, which is Noble's Tier III response contractor, admitted the difficulty in responding to condensate spills in a reply to the author on this subject, stating: *"You are correct that in the majority of cases of gas or condensate releases then it's simply a matter of 'Monitor & Evaluate' with no direct intervention."* The assumption that all gas and condensate will quickly float to the sea surface is also incorrect, as some may remain entrained in mid-layer water masses (as in *Deepwater Horizon*).

33. Chemical dispersants are not known to be effective in most condensate release scenarios, yet the Leviathan *Oil Spill Contingency Plan* (OSCP) relies on dispersant application as a primary response tool. Further, current Israeli dispersant restrictions prohibit dispersant use in water depths less than 20 m deep, or within 1 nautical mile of sensitive coastal habitats. This requirement needs to be revised to prohibit dispersant use in waters less than 200 m deep, or within 10 miles of shore. The operator should be required to conduct laboratory tests of the effectiveness of dispersants on

Leviathan condensate, and until effectiveness can be demonstrated, dispersants should not be approved for use on Leviathan condensate spills.

34. The Leviathan OCSP has insufficient discussion of transboundary spill response arrangements (e.g. with Lebanon, Egypt, Cyprus); in-situ burning and ignition risk; and wildlife response in a spill.

35. The OCSP contains inadequate discussion of technologies available for spill tracking and monitoring, including remote sensing technologies and tracking subsurface contaminant plumes, and does not adequately consider dispersion and safety issues regarding vapor emissions above a condensate release.

36. There is no discussion of pre-planning for conducting an environmental damage assessment (*Natural Resource Damage Assessment*, or NRDA) science program in the event of a major release of gas or condensate.

Other Significant Issues

37. There is no discussion of securing adequate financial liability coverage for the project, including environmental damage and unlimited liability for gross negligence. Israel is a party to several of the international oil pollution liability regimes, but these alone are insufficient. Israel should consider additional liability requirements to motivate responsible corporate behavior.

38. If the current design moves forward with the Leviathan Production Platform (LPP) 10 km offshore, the project should be required to use either Produced Water Reinjection (PWRI) as BAT, or to build a discharge pipeline from the LPP offshore to at least 500 m depth (about 10 km further offshore), from which to discharge produced water further from shore and beneath the photic zone/thermocline, reducing impact to the continental shelf ecosystem.

39. The project estimate of about 19 million tons CO2 emissions over the 30+ year lifetime of the project constitutes a dramatic underestimate. If the total the amount of natural gas projected to be produced (22 Tcf) from the project is considered, total CO2 emissions resulting from the project would exceed 1.2 billion tons. The Government of Israel should establish a carbon tax of at least $60/ton CO2e (comparable to Norway) on all carbon emissions.

40. Security risk of the project, particularly for the LPP and onshore infrastructure, is not sufficiently considered. Security risk alone argues against the LPP option, in favor of the FLNG option 125 km offshore.

41. The *Stakeholder Engagement Plan* (SEP) relies on conventional passive engagement, which is ineffective. As the Government of Israel is both financial beneficiary and regulator of the project, it has conflict of interest in

providing effective oversight on its own. To correct this, the project should be required to establish well-funded, representative *Israel Offshore Citizens' Advisory Council*, to authentically empower all stakeholders in working with industry and government to provide oversight of the project.

42. The Israeli government should establish a sufficient tax and royalty regime for revenue from its finite hydrocarbon resources, collecting at least 50% of gross revenues, and establishing a petroleum savings fund with at least 50% of annual government revenue deposited as an Israel Permanent Fund. Some government hydrocarbon revenues should be dedicated to subsidizing a renewable energy transition in Israel.

Given the above substantive concerns, it is my respectful recommendation that the Government of Israel suspend permitting for the Leviathan project, pending satisfactory resolution of all issues raised herein.

In particular, the Leviathan project should be redesigned to eliminate the near shore Leviathan Production Platform (LPP) and extensive seabed pipeline infrastructure, opting instead for either an FLNG facility offshore at the gas/condensate field 125 km offshore, and use of shuttle tankers to deliver LNG and condensate to Israel and other markets; or alternatively, an FPSO at the offshore gas/condensate field, transporting condensate via shuttle tankers and dry gas via seabed pipeline to shore. While FPSO or FLNG options would pose different risks that must be addressed, on balance either would dramatically reduce near shore risks and impacts of the project.

Clearly, the most environmentally responsible option for Leviathan development is for Noble to design and construct an FLNG facility. Alternatively, in order to avoid construction delays, the company should consider leasing an FPSO for initial development, and tie-in to its seabed gas pipeline system (in construction) to transport gas to shore and the INGL system, and condensate via tanker. Noble should offer its newly constructed LPP for sale to another offshore gas project elsewhere.

In addition, many systems-critical technical details are not reported, redacted, or not adequately detailed in the Leviathan documents. All of this must be remedied before the project proceeds.

2. Introduction

This Independent Expert Opinion was commissioned by *Guardians of the Coastal Plain, Citizen's Coalition Against Condensate*; *Homeland Guards*; and *Zalul Environmental Association*; non-governmental organizations in Israel. The groups requested independent technical review of several specific aspects of the Leviathan Offshore Gas Project now in development off the Israeli coast, specifically focusing on the environmental risks of a condensate release from the project. The author confirms that neither Guardians of the Coastal Plain, Homeland Guards, Zalul, or any other group - government, industry or civil society - asserted any editorial control over this independent opinion.

This review was limited to the documents translated and provided to the author, and completed without conducting a site visit to Israel. Documents provided for review included the following:

- Supplemental Lender Information Package (2016);
- Drilling EIA: Environmental Impact Report for Production, Drilling, Production Tests, and Completion – Leviathan Field (2016);
- Drill Leviathan EIA Amendment (2017);
- Production EIA: Environmental Impact Assessment for Installation, Operation and Maintenance of pipelines and Submarine Systems for Leviathan Field Development;
- Leviathan Production Platform (LPP) EIA: TAMA 37H NOP (National Outline Plan), EIA Offshore Section;
- Onshore EIA: TAMA 37H EIA NOP, Onshore Section;
- Relevant Appendices 6.1, 6.4, 6.9 to above EIAs;
- LPP EMMP: Environmental Management and Monitoring Program (EMMP) Civil 2 and Mechanic 1;
- Marine EMMP No. 1, Appendix 6.1
- OPIC Information Summary for the Public;
- Layout and Planning of NG Infrastructure in Israel from Offshore to Land (Israel MOE);
- Ratio Oil Exploration Partnership Presentation (2014);
- Noble Energy Mediterranean Ltd. (NEML) Oil Spill Contingency Plan (Jan. 2018);
- NOP 37/H Offshore Processing Scheme (PDI) Facilities Description & Quantification of Emissions and Discharges;
- Leviathan 4 – Environmental Monitoring Program Post-Drill Survey (2013);
- Environmental Impact Report for Production Drilling, Production Tests, and Completion – Leviathan Field (2016).

As of this writing, the current status of project development and permitting remains unclear to the author. The project schedule listed in the 2016 Drilling EIA states that offshore well drilling and completion would be underway at this time. The author was recently informed that construction of the LPP has been completed in Houston Texas (USA), and the platform is now awaiting tow-out to the selected site offshore Israel. As well, apparently several of the wells have been drilled and completed. Yet, there is much detail on this unavailable to the author, such as detailed Applications for Permit to Drill (APDs). This information gap presented a significant handicap to a comprehensive review of the project.

The Leviathan documents reviewed are poorly integrated, redundant, inconsistent, and contain several errors (e.g. units), making it difficult for the public to easily access the most significant information about the project. The 2016 Supplemental Lender Information Package, or other summary document, should have methodically synthesized and clarified all risks and mitigation for the project, in particular Worst Case Discharge condensate/gas releases offshore, but failed to do so.

Finally, while this review focuses on the failures and insufficiencies of the Leviathan documents, it is offered respectfully, and in the sincere hope that it will assist Israeli civil society, the Government of Israel, the companies, and potential lenders better understand the risks involved in the project, the potential effectiveness of proposed risk mitigation measures, and contribute to informed decisions. This review is offered in recognition of Israel's laudable goal of securing energy independence.

The author's professional experience in environmental aspects of offshore energy development and oil spills is summarized in Appendix I. The author looks forward to working with the public, government, and operators to make Leviathan as safe as possible.

3. Leviathan Project Summary

The Leviathan Offshore Gas project plans to develop a deepwater hydrocarbon reservoir in the eastern Mediterranean Sea 125 km off the north coast of Israel. Ownership of the Leviathan gas field includes Noble Energy Mediterranean Limited (39.66%), Ratio Oil Exploration (1992) Limited Partnership (15%), Delek Drilling Limited Partnership (22.67%), and Avner Oil Exploration – Limited Partnership (22.67%). Noble will be the operator of Leviathan. The Leviathan project is one of several offshore gas projects operating or in development off Israel, including Tamar, Mari-B and Noa, Hadera Deepwater LNG terminal, Shimshon Gas Field, Aphrodite/Ishai, Aphrodite Block 12, Dalit, Karish and Tanin, and Daniel East and West.

The Leviathan project envisions producing an estimated 22 trillion cubic feet (Tcf) of natural gas, 39.4 million barrels (bbls) of condensate, and potentially several hundred million bbls of crude oil (beneath the gas/condensate reservoir). The gas/condensate reservoir lies about 5,170 m beneath the seabed, in water depths from 1,540 m – 1,800 m (total measured depth from sea surface to reservoir of about 7,000 m). Reservoir formation pressure is expected to be approximately 590 bar (8,557 psi) with a temperature of 140° C, approaching conditions of High Pressure/High Temperature (HP/HT) reservoirs, thus requiring stringent safety measures.

The Leviathan development plan calls for eight initial wells (6 new and 2 sidetrack off existing two wells, Leviathan 3 and 4) and up to 29 total wells over project life of 30+ years. The initial production wells will be drilled by two Dynamically

Positioned (DP) rigs, either semi-submersible or drill ship, and are expected to take a total of 556 days to complete.

Natural gas and condensate production will flow together from the eight (8) initial high-rate deepwater wellheads, through 14” diameter infield flowlines to a seabed Infield Gathering Manifold in 1,629 m depth, about 10 km inshore from the wellheads. This seabed gathering manifold will be connected by two (2) 18” pipelines (to the Domestic Supply Module), and one (1) 20” pipeline (to the Regional Export Module) transiting 117 km to the near shore processing platform, the Leviathan Production Platform (LPP) on the continental shelf at 87 m water depth, about 10 km off the coast at Dor. Two (2) 6” MonoEthylene Glycol (MEG) pipelines will carry MEG from the platform to the deepwater wellheads for continuous hydrate (ice-like methane crystals) inhibition (two are used for redundancy in this production-critical component).

The subsea production system will be controlled from the LPP, via an open loop, multiplexed electrohydraulic system connected through a single 4” umbilical line running from the LPP to the infield control Subsea Distribution Unit (SDU), from where control will extend by additional umbilicals to remotely operated valves at the wells.

Leviathan production rates are expected to begin at 1.2 billion cubic feet (MMMscf)/day of natural gas, and between 2,500 - 7,630 barrels per day (bpd) of condensate, to existing markets in Israel, Jordan, and the Palestinian Authority, and expand to 2.1 MMMscf /day of gas when additional markets mature. The project also envisions the possibility of connecting the Leviathan wells to the Aphrodite Block 12 gas field now in development in the EEZ of Cyprus, about 45 km to the west, for export to Cyprus.

After dewatering, separation, and condensate stabilization at the LPP, recovered natural gas will flow through a 32” seabed pipeline, and condensate through a 6” seabed pipeline, to an onshore coastal valve station at Dor, from where gas will enter the Israel Natural Gas Line (INGL) pipeline system, and condensate will also transport via the INGL and via pipeline through Hagit to refineries at Haifa.

All together, the project is expected to include 352.5 km of subsea production pipelines, 235 km of MEG supply lines, and 117.5 km of electrohydraulic umbilicals for surface control (electrical and hydraulic) of subsea production infrastructure.

4. Condensate - General Characteristics

Condensates, also called Natural Gas Condensates (NGCs), are a complex mixture of hydrocarbons (pentane and higher homologues) associated with many natural gas reservoirs.[1] While under pressure in the geologic reservoir, they are generally in a gaseous state. As condensates are produced along with natural gas from the reservoir and pressure drops, they condense into a liquid phase. This condensation generally occurs during production at the wellhead, gas processing plants, or in gas pipelines. NGCs consist of hydrocarbons such as alkanes, isoalkanes, cycloalkanes, and aromatics within the range of C_2 – C_{30}, mainly falling between C_5 and C_{15} (including low boiling point naphthas, such as gasoline). Condensates are also referred to as natural gas liquids (NGLs). By comparison, natural gas is comprised largely (99%) of methane gas, and crude oil much heavier fluid hydrocarbons, again differing between reservoirs and even at different locations within reservoirs.

NGCs may contain over 100 different hydrocarbons, including benzene, toluene, ethylene, xylene (BTEX), and polycyclic aromatic hydrocarbons (PAHs). Some are similar to light crude oils absent heavier asphaltenes.[2] Condensates exhibit high variability between different reservoirs.

API Gravity is an inverse measure of petroleum density relative to water -- the greater the API Gravity, the less dense the liquid. Petroleum liquids with API Gravity less than 10 are heavier than seawater and sink. Petroleum is generally classified as to API Gravity as follows: Heavy oil API 0-20; Medium oil API 20-40; Light oil API 35-55; condensate API 50-85; and LNG/CNG API 80-90. API Gravity measures for Leviathan condensate are reported at 43.2, although API Gravity of 34.2 is used for some Leviathan spill models. This is heavier than most condensate.

Condensates discussed in the Canada Screening Assessment ranged from API 39.9 (Specific Gravity 0.83) to API 78.1 (Specific Gravity 0.67); viscosity ranged from 0.41 cP (centipoise – dynamic viscosity) to 2.7 cP; and water solubility ranged from insoluble to 74.7 mg/L.[3] Condensates with API 39.9 weigh approximately 824 kg/m3; while those of API 78.1 weigh 660 kg/m3.

Condensates contain between 0.15%-3.6% of the carcinogen benzene, averaging about 1%, and exhibit varying degrees of solubility and viscosity.[4] Composition of Leviathan condensate is expected to be predominantly C13 – C19 (24.46%), Octanes (10.26%), C30+ (10.07%), C11 (9.93%), Heptanes (8.25%), n-Nonane (7.59%), and n-Decane (7.01%).[5]

Condensates are generally highly volatile and moderately (and variably) soluble in water. The BTEX component contributes most of the solubility of condensates, with benzene being highly soluble (up to 1,790 mg/L). Solubility of the complex condensate mixture is often different than it is for the individual components alone, thus there is a synergistic effect on solubility.[6]

Condensates are used for diluting heavy crude oil, and refinery feedstock for gasoline, jet fuel, and other industrial uses. World production is now approximately nine (9) million bbls/day (bpd), and increasing by about 3%/yr.

While most condensate spills at sea are small, from 1–70 bbls, there have been at least two very large condensate spills at sea:

1. 1980, *Juan Antonio Lavelleja* collided with a breakwater in the port of Arzew, Algeria, spilling a reported 28,000 tons of condensate.

2. 2018 *Sanchi* condensate tanker disaster in the East Sea off China (ship-to-ship collision and sinking with all hands), releasing its entire cargo of approx..113,000 tons of Iranian condensate – the largest condensate release in the historic record.

Unfortunately, neither of these large marine condensate spills was subjected to comprehensive environmental damage assessment.

Condensate is light, volatile, and acutely toxic (in concentrations less than 1 ppm). Condensate behaves very differently than crude oil when spilled, as it is not known to form distinct and visible surface slicks as with crude oil spills. While the impact on the sea *surface* may be less, the impact of the dissolved or entrained fraction in the subsurface *water column ecosystem* may be acute and serious. The dissolved and dispersed hydrocarbon plume would be submerged and not visible at the sea surface.

If the condensate ignites, much of the hydrocarbon will disperse atmospherically as burned particulates in the smoke plume, but burn residue may also settle on the sea surface and potentially lend itself to containment and recovery. The dissolved or entrained fraction of the condensate released would form an acutely toxic, three-dimensional plume that disperses and dilutes with water currents. Although they are generally less persistent than heavier crude oil spills, condensate hydrocarbons can persist for months (depending on water/air temperature, dispersion rate, biodegradation, etc.).

When released at the sea surface, most condensate will volatilize (evaporate into a gaseous phase to the atmosphere), and the remainder will dissolve in seawater, emulsify (generally into unstable emulsions), adhere to suspended particulates, biodegrade, weather, and disperse with water currents. The water-soluble fraction (WSF) of condensate is similar to light crude oils, with light polycyclic aromatic hydrocarbons (PAHs) dominant.[7] Most scientific information on the fate and effects of condensate spills derives from small surface releases.

However, when condensate is released beneath the sea surface (such as from a failure in the Leviathan deepwater offshore production infrastructure), a higher percentage of the condensate will dissolve as it drifts toward the sea surface. This is particularly true if the release occurs from the deepwater wellheads and pipelines at 1600-1800 m depth. Some condensate released at depths involved in the Leviathan project may even entrain in deepwater masses, such as the higher salinity Levantine Intermediate Water below 200 m, or Mediterranean Deep Water below 800 m, and remain in these waters for some time.

In deepwater releases, while large droplets (up to 5 mm diameter) will rise within hours to the sea surface, small droplets (to 0.5 mm) will rise more slowly, taking up to a day to surface.[8] As reported by SINTEF for deepwater (below 1000 m) releases:

> "Fine droplets (below 100 microns) may stay in the water for weeks or even month(s) before they eventually reach the surface. However, factors like vertical turbulence mixing in the water column, density stratification and cross flows will contribute to keep such fine small droplets submerged for even prolonged periods (Johansen et al., 2003)."

This dynamic is precisely what occurred with much of the 400,000 tons of methane and small oil droplets released along with oil from the 2010 Deepwater Horizon blowout in the U.S. Gulf of Mexico.[9] Most of this huge volume of methane did not, as previously expected, reach the sea surface and atmosphere, but instead remained entrained in large subsurface plumes drifting with mid-water currents. These subsurface methane plumes remained intact in the water column for months, leading to significant enhancement in methanotrophic bacterial production, oxygen depletion, and was ultimately taken up by plankton in mid water depths. Such a physical dynamic is possible for a deepwater Leviathan release, but was not considered in the EIA documents.

There is little available research regarding the effect of water pressure at these depths on condensate release behavior, dissolution, or ecological effects. This represents a significant gap in predicting ecological effects of a major deepwater condensate release from Leviathan. Regardless, it is evident that a deepwater release of condensate from the Leviathan project would be expected to cause far greater impact on the pelagic (water column) ecosystem than would a release at the sea surface.

Due to its volatility, the persistence of significant condensate on the sea surface is expected to be short term, from days to weeks. However, studies have shown that spilled gasoline (a component of, and surrogate for, condensate) can have a half-life of up to 6 months in water.[10] Some components, including the heavier aromatics, alkanes, and PAHs, have shown half-lives exceeding 6 months in water and more than a year in sediments. These heavier, lipophilic components are also prone to bioaccumulation. And, weathered condensate on the sea surface and shoreline will degrade more slowly.

Environmental impacts of condensate spills can include lethal and sub-lethal injury across all components of a marine ecosystem, including plankton, fish, benthic invertebrates, seabirds, and marine mammals. Condensate is absorbed into marine organisms through ingestion, respiration, and direct contact (e.g. through gill tissues of fish). Acute toxicity is reported in some marine species exposed to concentrations of weathered condensate as low as 0.03 mg/L (0.04 ppm, or 40 ppb).[11] This is considered a high toxicity. Similar toxicity results are reported for heavy condensates as well. With such toxicity, monitoring must achieve high sensitivity and analytic precision, yet no analytic details were provided in Leviathan documents.

Water-soluble fractions of condensate have been shown to be toxic to coral larvae, leading to increased mortality, reproductive injury, delayed metamorphosis, and reduced growth.[12] These results suggest significant risk to early life stages of organisms (e.g. fish larvae, plankton, etc.) in the pelagic ecosystem.

Subsurface condensate releases, where volatilization is greatly reduced, would be expected to exert far greater toxicity on marine organisms than surface releases. Of particular interest here is that in most studies, weathered condensate (over 48 hours) exerted far greater toxicity than fresh condensate.[13] In addition to the known carcinogen benzene in condensate, other components of toxicological concern include *n*-hexane (neurotoxicity), toluene (ototoxicity), ethylbenzene (possibly carcinogenic), xylene and *n*-pentane. Epidemiological studies in petroleum workers have reported increases in incidence and mortality from leukemia, skin cancer, kidney cancer, and lung cancer in petroleum workers.[14]

A one-day exposure to condensate-contaminated surface water on a ranch in California led to the deaths of 30 sheep over a 21-day period, due to aspiration pneumonia, myocardial necrosis, renal damage, and meningeal edema.[15] One can broadly extrapolate such acute toxicity if marine mammals and birds are directly exposed to high concentrations of condensate.

Beyond these acutely toxic effects to marine organisms, ecological impacts can last considerably longer than the environmental persistence time of condensate. This has been proven in oil spills, such as ecological impacts from the 1989 Exxon Valdez oil spill persisting today, almost 30 years later.[16] If a major condensate release impacts reproduction in long-lived marine animals, for instance marine mammals, effects can persist for several generations. It is possible that impacts to genetically distinct populations of long-lived marine animals (e.g. whales), with limited size and range, can be permanent. This has been reported in one killer whale population in Alaska (AT1), that was heavily impacted by the Exxon Valdez spill, and is now expected to go extinct due to the loss of all reproductive females from the small population in the spill.[17]

The Environment Canada synthesis summarizes condensate (Natural Gas Condensate) ecotoxicity as follows:

> "Based on the available information, NGCs contain components that may persist in air and undergo long-range atmospheric transport. They also contain components that may persist in soil, water and/or sediment for long periods of time, thus increasing the duration of exposure to organisms. NGCs are also expected to contain components that are highly bioaccumulative. Studies suggest that most components will not likely biomagnify in food webs; however, there is some indication that alkylated PAHs might."[18]

Thus, condensate releases are considered a significant environmental risk.

5. Leviathan Oil Spill Models

Two independent oil spill modeling approaches were used for the Leviathan project:

1. OSCAR (Oil Spill Contingency and Response), developed by the Norwegian Naval Research Institute (SINTEF), and conducted for the Leviathan project by Genesis.

2. MEDSLIK, developed by the Oceanographic Institute of Cyprus, tailored to Mediterranean Sea conditions, conducted for the Leviathan project by Dr. Steve Brenner of Bar Ilan University.

Both models appear robust and useful. However, the input spill volumes that were modeled should be revised significantly upward for a Worst Case Discharge (see below). Due to the organization of the documents and analyses, it is difficult to summarize and evaluate the various worst case discharge estimates. As well, several units in documents are incorrect, confusing m3 for bbls (e.g. condensate storage on the LPP), or oiled shoreline measurements of m3/km for m3. The 2016 *Supplemental Lender Information Package* (SLIP) should have methodically synthesized, corrected, and clarified all of the spill modeling results from all project documents, but failed to do so. This makes it extremely difficult for the public to understand the potential spill volumes from the project.

The following statement, from the LPP EMMP, is incorrect and misleading (*emphasis added*):

> "It is important to emphasize that the data in the tables below represents the *most extreme scenarios*, and does not take into account the expected intervention of the Company and its contractors in order to mitigate the damage. In practice, the implementation of the Company's emergency plan will allow the taking of a variety of actions in order to deal with the spill, which *will enable a significant mitigation of its effect*. In view of the platform's proximity to the coastline, the depth of the water and the existing natural reserves in the area, most of the spillage collection activities will concern mechanical measures and preparations for the mitigation of the damage to the coastline, Shore Line Cleanup and Assessment Technique (SCAT), depending on the coast type, sensitive land use, etc."

First, modeled spill volumes do not represent "most extreme scenarios" (see below). Next, the claim that spill response "will enable a significant mitigation of its effects," is also not supportable. The mention of "mechanical measures" for condensate response is not realistic (see OSCP section below). API Gravity for Leviathan condensate is reported at 43.2, although API Gravity of 34.2 is used for some Leviathan spill models. This is significantly heavier than condensate, more appropriate for medium crude oils, and thus use of this API gravity may have skewed spill dispersion models. This should be evaluated.

And the spill models do not adequately account for midwater entrainment of small (less than 100 micron) condensate droplets from deepwater infrastructure, or adherence of condensates to sediment in near shore and shoreline oiling situations.

5.1 Drilling

The MEDSLIK model assumes a total condensate release of 857 m3 x 30 days = 25,110 m3, with 37% evaporating in first 2 days, leaving 15,819 m3 on the sea surface. This total release would be approximately 170,748 bbls (which can be rounded to 170,000 bbls). The model predicts that at the end of 30 days, 44% of this offshore condensate spill will have evaporated, leaving 56% (95,619 bbls) in the marine environment.

It must be noted that, while the modeled diesel spill volume was reported (8,415.3 m3), the modeled volume condensate spill was redacted from the Drilling EIA. However, the data was retrievable, and the redacted condensate release volume was set at 857 m3 (5,827 bbls)/day x 30 days. It is highly unusual and unacceptable to redact this modeled release volume, and raises a number of very serious concerns regarding the transparency of the project (see redaction discussion below).

Assuming an average surface slick thickness of 1 micron – 0.04 micron, area of surface contamination is estimated from 15,819 km2 to 395,475 km2. At a conversion factor of 6.8 bbls/m3, the modeled 25,110 m3 release would total 170,748 bbls. However, in Appendix N of the Drilling EIA, the modeled condensate blowout rate is reported to be 5,264 bbls/day x 30 days, totaling 157,920 bbls. The reason for the discrepancy is unclear, but likely due to a conversion difference (from m3 to bbl). Regardless, these total release volumes are relatively close to one another. It is similarly unclear why slightly different API gravity measures were used in various models.

The MEDSLIK model is rigorous and useful in providing a general understanding of expected fate for a large condensate release. However, two significant issues with the model are:

> 1. The modeled volume discharge (857 m3 x 30 days = 25,710 m3) is clearly not a Worst Case Discharge (WCD) scenario; and
>
> 2. The assumption that: "The slick is assumed to be positively buoyant and rises instantaneously to the surface where it floats and is dispersed by the currents and the winds," is not necessarily a valid assumption.

It is unclear how the 857 m3/day (5,827 bbls) and the 30-day total release period were selected for the modeling exercise. By comparison, the flow rate from the

Deepwater Horizon blowout in the US Gulf of Mexico (from the Macondo reservoir at comparable depth and pressure as Leviathan) averaged 62,000 barrels per day (bpd) over 87 days, for a total release of estimated at 4.9 million bbls, with surface contamination ultimately covering 180,000 km2. The 2009 Montara oil and gas platform blowout in northwest Australia continued from Aug. 21 – Nov. 3, a total of 74 days, at an estimated rate of 2,000 bpd, for a total release of 4,500 m3 – 34,000 m3 (30,600 bbls – 231,200 bbls). And the Point Thomson gas/condensate field on Alaska's North Slope modeled a 27,000 bpd x 15 days condensate spill, for a total release of 405,000 bbls.[19]

Total's Elgin gas and condensate blowout in the Scottish North Sea is another example of a high temperature/high pressure gas blowout that continued longer than 30 days. The Elgin well blew out during plug and abandonment procedures on Mar. 25, 2012, releasing 7 million cf/day of methane into the North Sea for over 7 weeks, until mud and cement pumping into a relief well was completed May 16, 2012.[20] The blowout was attributed to corrosion of the well casing.

Given the relative similarities in reservoir depth and pressure, Leviathan models should assume that a worse case discharge (WCD) condensate release from one of Leviathan's deepwater wells could continue for as long as, and be as large as, any of these blowouts. In fact, given the reported 2011 blowout of the exploratory Leviathan 2 well while drilling, which continued for 16 months until plugged, a correspondingly longer time period for a wellhead blowout should be modeled. At a minimum, at least twice the release period (60 days) should be modeled for a Leviathan blowout. As well, it must be noted that 16 months to regain control of a failed well is an unacceptable length of time, and this calls into question the effectiveness of Noble and Delek's well control capabilities.

As to the fate of condensate released from a deepwater well, some could become entrained in deep or mid-level water masses (e.g. under the thermocline or below 200 m) for some time post-release. Indeed, elsewhere in the discussion it is predicted that a substantial amount - e.g. 14% - would remain dispersed (vertically mixed) in the water column. On the modeled release of 170,000 bbls, that would be 23,800 bbls. On a larger WCD release of 350,000 bbls, this would be 47,600 bbls of condensate remaining in the water column.

And the statement: "In general the main concern is the amount and location of the oil that will potentially reach the coast," betrays an unreasonable (yet conventional) shoreline oiling bias in such oil spill impact assessments. In fact, from an ecological standpoint, the greatest concern from a large offshore condensate release is for the offshore pelagic ecosystem, not the shoreline. The Eastern Mediterranean continental shelf ecosystem is a unique and fragile biological system that could be seriously impacted by such a major pollution event.

The MEDSLIK model projects that 15.8% of the offshore surface contamination from the Drilling condensate spill will reach shore, contaminating 388 km of shoreline, with up to 941 bbls/km of shoreline, from the shores of Egypt to Syria. But again a discrepancy is that in one place the model projects 2,000 m3 on shore, yet Table 4-8 in the Drilling EIA projects 13,000 m3 on shore. [Note: Table 4-8 actually states 13,000 m3/km to reach shore, which seems to be an error in units].

Importantly, the MEDSLIK model for the drilling condensate release projects only 44% of the condensate being evaporated at the end of 30 days. Thus, 56% would remain in the marine environment for a considerably longer period. And given the discussion above regarding reports that weathered condensate is far more toxic than fresh condensate, this represents a significant gap in the effects analysis.

Given all of the above points, it is recommended here that the project model a 350,000 bbl condensate release during Leviathan offshore drilling, twice that in current models.

5.2 Production (subsea pipeline, wellheads to LPP)

For the Production (seabed pipeline) phase, the modeled Worst Case Discharge was approximately 1,220 bbls – 1,320 (194 m3) bbls, based on total pipeline inventory + 5 minutes to shut-in the pipeline. This represents a significant underestimate of potential Worst Case Discharge volume, and should be revised upward. This underestimate derives from the assumption that a failed pipeline will be detected and promptly shut-in with proper functioning of the Surface Controlled Sub Surface Valve (SCSSV) system from the Leviathan Production Platform.

Upon detection, operators would close the Infield Gathering Manifold (IGM), relevant subsurface isolation valves (SSIV), and the topside safety valves at the riser tie-in point. The scenario assumes complete pipeline isolation in 2 minutes or 5 minutes. This ignores other pipeline failure scenarios, including a failure in detection sensor systems or lost connectivity within the system. All of such is a real possibility that must be evaluated and mitigated.

Again, the modeled scenario assumes the gas will all rise to the surface and evaporate to the atmosphere. "…the gas will eventually leave the water column and enter the atmosphere" (p. 16 D). But as in the *Deepwater Horizon* release, this may not be the case. Small droplets of condensate/gas mixture (less than 100 microns) can remain in the water column for weeks or months. The spill scenario modeled for the Production phase dramatically understates the potential release of gas and/or condensate from a catastrophic seabed pipeline failure.

5.3 Leviathan Production Platform (LPP)

Different discharge scenarios are used by the two models for condensate spills from the LPP. The OSCAR model uses a 1,000 bbl spill, and MEDSLIK uses a 100,000 bbl spill from a potential FSO (Floating Storage and Offloading) tanker/facility associated with a platform (NOP 37/H – Guidelines). However, the Worst Case

Discharge from a condensate tank failure on the LPP would be five times larger than the 1,000 bbls modeled. In a May 5, 2018 letter, MoEP stated as follows:

> "The total amount of condensate expected to be stored in the platform and pipelines to the shore will not exceed 5300 barrels (850 m3)."[21]

Thus, although the FSO condensate storage option was not selected in the final LPP design, the loss of 5300 bbls of condensate from a tank failure on the LPP represents a Worst Case Discharge and should be modeled.

Elsewhere, OSCAR models a very small condensate release, only 15.9 bbls and 75 tons of gas (Chapter D, p 14). This is based on a total release time of only 3 minutes, including only 2 minutes to activate the subsurface isolation valve (SSIV) closing the system. The sole scenario considered was a dropped object from the LPP rupturing a segment downstream of the SSIVs (subsurface isolation valves), which would close "upon positive detection of a loss of containment," and isolate the pipeline.

Both models assume significant (50%) evaporation within 24 hours, and both estimate significant shoreline contamination between Atlit and Haifa. In the various scenarios, condensate contamination is projected to reach shore from 18 hours to several days after release. Shoreline condensate in OSCAR model from LPP maximum is 32 tons, which is reported to be 24% of the spill.

OSCAR projects water column hydrocarbon concentrations between 300 ppm - 400 ppm, which given toxicity reports cited in above sections, is considered acutely toxic to marine organisms.

5.4 Ecological Impacts

Regarding ecological impacts expected from condensate spills, a good summary (although general) is found in Section 4.8.6 in the TAMA offshore EIA. This summary is attached in App. 1 (verbatim, without citations), in order to make the information more easily accessible to the general public.

However, it is clear that the statement in the documents that: *"No High risk impacts were identified in the evaluation from routine activities or accidental events*," is not supportable.

For instance, the Drilling EIA states (p.13, emphasis added):

> "Both of the accidental spill scenarios (a fuel spill and a condensate spill from a blowout) were evaluated as having several *Moderate impacts.* For the fuel spill, potential impacts on seabirds and migratory birds as well as coastal habitats and infrastructure were rated as Moderate. For the condensate spill, potential impacts on marine mammals, sea turtles, fishes, seabirds and migratory birds, fishing activities and marine farming, and coastal habitats

> and infrastructure were rated as *Moderate*. The condensate spill has the potential for greater consequences because of the extended time period (30 days) for the spill event and the greater volumes of oil potentially reaching the shoreline."

However, if 170,000 bbls of condensate are released from a Leviathan deepwater well or pipeline failure, spreads over 395,000 km2 of coastal ocean, results in water hydrocarbon concentrations in excess of 300 ppm, persists for months, and contaminates 388 km of shorelines from Egypt to Syria with over 88,000 barrels of toxic weathered condensate, then clearly ecological impacts would be high. In particular if a larger worst-case release is considered, ecological impacts should be considered "high." Understatement of potential spill impacts for Leviathan derives from the conventional industry tendency to focus almost exclusively on shoreline impacts, while in many of the Leviathan spill scenarios, most of the impact will be to offshore pelagic ecosystems. Risk table 4.9 in the Drilling EIA (p. 210-211) should be adjusted accordingly.

The Leviathan environmental impact assessments do not adequately detail the biological uniqueness of the deep-sea ecosystems of the Levant Sea, which is described as follows:

> "…a unique and delicate marine ecosystem, whose rich biological communities host rare species of deep-sea sponges, worms, molluscs and cold water corals – some of which are thousands of years old."[22]

Although the conventional view of the deep sea region of the Levant Sea is of a relatively non-diverse, simple biotic assemblage, more recent studies report a rich and diverse deep sea fauna, with 60 species of fish, crustaceans, and mollusks newly recorded in the region, and several species new to science.[23] The Leviathan documents do not provide sufficient detail regarding this unique deep sea ecosystem, and in particular potential impacts of the project.

In addition, there is little discussion of the impacts of a major natural gas (largely methane) release in the documents. This is a significant gap in the assessment of environmental impacts. As reported in the 2010 Deepwater Horizon wellhead blowout, up 40% of the release volume was methane. This release behaved in unexpected ways, remaining entrained in midwater pelagic ecosystem for months, leading to enhanced microbial populations and extensive anoxic conditions in the Gulf. The potential environmental impacts of a large-scale gas release from Leviathan need to be more extensively assessed and reported to the public. Natural gas (methane) is known to be toxic to marine organisms, particularly so at higher water temperatures off the coast of Israel.

Finally, if extensive shoreline contamination occurs as a result of a large condensate release, some of the toxic weathered condensate will adhere to beach sediment (sand, silt, etc.), and some will then transport back offshore with tidal mixing and near shore currents. This will contaminate near shore benthic communities. This potential impact was not discussed, and should be.

6. Risk Assessment

Some quantitative risk assessment for various project components is reported in the documents, but it is unclear that a rigorous, independent, integrated risk assessment has been conducted.

The independent risk assessment should methodically and quantitatively evaluate all risks and potential consequences deriving from the project, including common-cause failures and extraordinary, catastrophic casualties. Generally, probabilistic risk assessments understate the risk of catastrophic failure, lead to less than *Best Available Techniques/Technology* (BAT) systems design, and promote dangerous complacency in government and industry. In a real sense, if the risk of a catastrophic event is not zero, it should be considered to be 100% -- that the event will happen, sooner or later. As Leviathan production is expected to continue for 30+ years, the chance for a major pollution disaster is significant. This is the best framework with which to evaluate and reduce all possible risk.

Even competent risk managers generally do a poor job at assessing and managing risk in complex systems. An example is the NASA Space Shuttle program in the U.S. After the 1986 Challenger disaster (caused by a very simple malfunction of the fuel tank gasket "O" ring), many technical inquiries were conducted, and NASA concluded that all risks had been identified and remedied, and then restarted the program. Then, the 2003 Columbia disaster occurred, caused by another very simple problem that was not anticipated by the engineering analyses on Challenger and risk assessments (a small piece of the gantry broke off during liftoff, pierced the forward edge of a wing, exposing the area to excessive heat on reentry, and the shuttle exploded). The point here is that even in the most highly engineered, sophisticated, complex systems, we make *low probability/high consequence* mistakes. The people of Israel should expect and plan for such with the Leviathan development, and rigorously analyze and mitigate all such risks.

Leviathan planning documents do not sufficiently envision and plan for catastrophic failure, which they do only superficially. To the contrary, the Leviathan documents assume success. This attitude leads to dangerous complacency and lack of vigilance.

History is full of the tragic consequences of such complacency and arrogance. For instance, seeking approval to build the 800-mile Trans Alaska (oil) pipeline and marine terminal in the early 1970s, politicians assured the American public that "not one drop" of oil would ever be spilled into coastal waters of Alaska, as best available technology would be used to prevent such. But after securing the right-of-way to build the pipeline, the promise of best available technology was abandoned. Twelve years after the opening of the Alaska pipeline and terminal, the fully loaded Exxon Valdez grounded on a well-marked reef, spilling hundreds of thousands of barrels of toxic oil into the pristine coastal ecosystem of Prince William Sound. The environmental injury continues to this day.

Just 5 months prior to the *Deepwater Horizon* disaster in the U.S. Gulf of Mexico, representatives of the U.S. oil industry and government regulators, in testimony to a U.S. Senate hearing regarding the August 2009 *Montara* offshore platform blowout in the West Timor Sea (NW Australia), assured the U.S. Congress that offshore drilling in the Gulf of Mexico was perfectly safe, and the regulatory process was sufficient to prevent such disasters in the U.S.

And just three weeks before the 2010 *Deepwater Horizon* disaster, then U.S. President Barack Obama opened large areas of the U.S. Outer Continental Shelf (OCS) to oil and gas drilling, assuring the American public that: *"Oil rigs today generally do not cause spills. They are technologically very advanced."*

This very same dangerous complacency, hubris, and risk tolerance is evident today in Leviathan planning.

7. Mitigation - Spill Prevention

As discussed below, it must be honestly admitted by project proponents and the Government of Israel that there is no realistic possibility of effectively containing or recovering a condensate or natural gas release at sea. Once released, the environmental damage from natural gas and/or condensate will occur, irrespective of any response effort. Thus, mitigation of these impacts must focus on *prevention* of releases.

Regarding risk of catastrophic failure of project components and/or a catastrophic environmental release of hydrocarbons, risk needs to be methodically assessed. On this, the documents reviewed simply do not provide enough detail to confirm the company's safety assurances. In general, the documents overstate the potential effectiveness of the project's risk mitigation and response plans, and its claims regarding risk mitigation are qualitative, vague, and unsubstantiated.

For instance, the documents do not present a clear well blowout or pipeline spill prevention plan - just general assurances - including leak detection, well design and control, pipeline design, personnel training, third party services, management of change, near-casualty reporting and investigation, risk assessment, and equipment maintenance and surveillance. There is no discussion of an Operations Integrity Management System (OIMS).

Although several deepwater gas wells have been drilled successfully in recent years off the Israel coast with no major reported hydrocarbon release, such a catastrophic failure could occur on any of the wells to be drilled in the future. It should be noted that prior to the 2010 *Deepwater Horizon* blowout in the U.S. Gulf of Mexico, hundreds of such wells had been drilled, most with few loss of well-control incidents. The lesson here is that the past does not always accurately predict the future in this regard. The Leviathan documents project a sense of complacency about the very real risk of a catastrophic hydrocarbon release.

The Drilling EIA simply states:

> "Best industry practice will be used during all drilling phases. After each new well is drilled, it will be temporarily abandoned and secured with multiple barriers pending completion operations by the second drilling rig. Temporary abandonment will be conducted in accordance with MNIEWR guidelines."

Obviously, this is insufficient with which to judge the rigor of the project's safety and spill prevention systems (See below).

7.1 Well design and control

The project documentation needs to recognize, detail, and confirm the project will meet the increased safety standards imposed in the U.S. after the 2010 *Deepwater Horizon* disaster.[24] In particular, the project documents must discuss the U.S. *Bureau of Safety and Environmental Enforcement* (BSEE) Final Rule (30 CFR Part 250) published on August 10, 2012: *Oil and Gas and Sulphur Operations on the Outer Continental Shelf–Increased Safety Measures for Energy Development on the Outer Continental Shelf***.** This offshore Drilling Safety Rule in the U.S., established new casing installation requirements, new cementing requirements, requires independent third-party verification of blind shear ram (BSR) capability and subsea BOP stack compatibility, requires new casing and cementing integrity tests, establishes new requirements for subsea secondary BOP intervention, requires function testing for subsea secondary BOP intervention, requires documentation for BOP inspections and maintenance, requires a Registered Professional Engineer to certify casing and cementing requirements, and establishes new requirements for specific well control training to include deepwater operations.

The documents do not present a *Critical Operations and Curtailment Plan* (COCP), for moving a rig off location during an emergency situation, as is required in the U.S. The COCP needs to detail specific procedures for responding to such things as adverse weather; unavailability of equipment, materials, or personnel; or well control issues. The COCP needs to identify planned and unplanned critical operations, such as drilling into a zone capable of flowing oil or gas, coring, pulling out of the hole, wire logging, running casing, circulating, cementing, attempting to retrieve lost items in the well, open-hole sidetracking, drilling into a lost circulation zone, remedial well work, anchor line tensioning, refueling, or accidental riser disconnect. The COCP must identify the amount of time expected to secure the drilling operation, including time (in hours) necessary to disconnect the Lower Marine Riser Package (LMRP) from the BOP and temporarily abandon the well, and to move off the site. And the COCP must clearly establish a drilling curtailment decision process, as well as training of key personnel in this process.

Again, as noted above, the Leviathan planning documents do not sufficiently envision and plan for catastrophic failure, which they do only superficially. To the contrary, the documents assume success. This attitude leads to dangerous complacency and lack of vigilance.

In fact, project documents confirm that an *inadequate* risk reduction standard would be used for the project. While documents recite the intention to employ *Best Available Techniques and Technology* (BAT), also called *Best Available & Safest Technology* (as required in U.S. regulation), it is clear the Leviathan project does not intend to meet a BAT standard. To the contrary, the documents state that the operator will employ a risk reduction standard of *As Low As Reasonably Practicable* (ALARP). An ALARP standard implies that not all *Best Available Techniques and Technology* risk reduction measures will be incorporated into the project, particularly if, at the discretion of the company, they are deemed too costly, too difficult, too time-consuming, or otherwise "not reasonably practicable." In essence, ALARP is not BAT/BEP. If BAT is required, then ALARP is insufficient. *This is a very important point that the Government of Israel needs to clarify.*

Given the sensitivity of environmental and social resources in Israel, the region should clearly be considered a *High Consequence Area* (HCA) for petroleum development (as defined in API standards), thereby requiring enhanced design and operational standards to reduce risk with BAT to *As Low As Possible* ("ALAP"). A High Consequence Area is generally considered to include infrastructure through population areas, drinking water sources, and highly sensitive environments. These areas of infrastructure then receive greater safety design standards. It is clear that these enhanced design standards are indeed best Available Technology (BAT), and it is recommended here that such BAT be employed on all components of Leviathan. Additionally, *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* similarly requires risk to be reduced to *As Far As Possible.*[25] The Leviathan project should be held to this standard.

The documents omit reference to, or commitment to comply with, important American Petroleum Institute (API) Standards, including, but not limited to, the following: API Standard 53: *Blowout Prevention Equipment Systems for Drilling Wells;* API Recommended Practice (RP) 65 Part 2: *Isolating Potential Flow Zones During Well Construction*, addressing best practices for cementing; API Spec 16A: *Specification for Drill-Through Equipment*; API Spec 16D: *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*; API Spec 17D: *Specification for Subsea Wellhead and Christmas Tree Equipment*; API RP 17H; ISO 13628-8: *Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems;* and API RP 75: *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*. Many of these are incorporated by reference into the U.S. offshore Drilling Safety Rule (BSEE, 2012), with which Noble commits to meet.

Although the EIAs assert the project will meet U.S. BSEE standards, they do not cite the *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations*.[26] If the Leviathan project is to meet global industry best practice and BAT standards (which it should), it should cite and commit to meet the relevant *2013 EU Offshore Drilling Directive* as well as all requirements of the U.S. *Bureau of Safety and Environmental Enforcement* (BSEE), *American Petroleum Institute* (API), *American Society of Mechanical Engineers* (AMSE), *American National Standards Institute* (ANSI), and other best global best practice standards as appropriate.

The documents do not present evidence that a robust well integrity Risk Assessment for specific well designs has been conducted, or that such will be conducted prior to drilling, as required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations*. The well integrity Risk Assessments should focus particular attention on the expected difference between pore pressure and fracture gradient of surrounding rock strata.

The documents do not provide sufficient detail regarding expected reservoir characteristics. The geology of the proposed well sites is largely redacted. Computer simulations and hydraulic modeling can accurately predict the downhole pressures that may be encountered. The documents need to present the predicted *Maximum Anticipated Surface Pressure* (MASP) for the wells, and *Maximum Anticipated Wellhead Pressures* (MAWHP).

Drilling mud engineering is a critical element of a safe drilling program, particularly for deepwater wells. Precise calibration of mud (weight, viscosity, etc.) must be identified that will maintain well control. If the mud weight is too high, the surrounding formation may fracture, leading to a loss return event and potentially an influx of hydrocarbons into the well. If the mud weight is too low, then the well is in an underbalanced condition, also conducive to flow into the well and a wellhead blowout. Drilling mud properties that are not reported for the proposed deepwater Leviathan wells include viscosity, yield stress and gels, compressibility, gas solubility, stability to contaminants and aging, weighting, mud formulation, application and control, mud additives (e.g. particle size of barite to be used), compressibility, and pressure-volume-temperature (PVT) analysis. This should include a discussion of control of impurities, such as clay, carbonate, iron, etc., that may compromise mud integrity or function.

The documents omit details for the cement and cementing procedures to be used. This is a safety-critical element that must be discussed in detail. It is well known that cementing problems, including the annulus between casings and the surrounding rock formation and the cement plugs in the well bore, constitute one of most significant risk factors for blowouts. Particularly in deepwater wells, cement formulation and application is an extremely important, safety-critical aspect. The project must cite, and commit to comply with, enhanced cementing requirements in the new offshore drilling safety rule in the U.S.

The documents do not identify a rigorous process for deciding and confirming cement specifications, and the testing procedure for cement slurry formulation, including testing procedures prior to application.

An important conclusion reached regarding the *Deepwater Horizon* blowout was that: "*The failure to properly conduct and interpret the negative-pressure test was a major contributing factor to the blowout*."[27] On this, the Leviathan documents do not detail the pressure tests that will be performed prior to mud displacement and abandonment. In particular, the negative pressure test is a critical procedure to test integrity of cemented final casing string or liner, where mud is removed from the well bore, replaced with less dense seawater, to determine if pressure increases in well bore that might indicate a dangerous flow of hydrocarbons into the well. This procedure needs to be discussed in detail.

The documents do not discuss the specific procedure and guidelines that will be used to monitor kicks (short-term pressured hydrocarbon releases) from wells. They need to detail a kick monitoring system (e.g. Kick Alert Status), with successive levels of alert, and procedures for responding to such alerts. Early detection of flow is critical. It should be noted that the influx of hydrocarbons into the Macondo well on the *Deepwater Horizon* was not detected until 50 minutes after flow had started, rendering well control more difficult.

In addition, both Measurement While Drilling (MWD) and Logging While Drilling (LWD) tools in the Bottom Hole Assembly (BHA) are discussed, but no final determination had been made at the time of EIA publication. It is important to detail how operators will collect and analyze real time drill data, and the contingency plan if well data transmission is lost.

7.2 Redaction

A serious concern in the Leviathan documents is that most of the systems-critical details, including those for well design and control, are simply redacted/withheld. This extensive redaction in systems-critical information is clearly unacceptable.

Section 4.3.5 of the Drilling EIA generally states:

> "Mitigation for accidental spills includes both spill prevention and response measures. Noble Energy will use safe drilling practices during its activities in the Leviathan Field to reduce the likelihood of an accidental spill. Best industry practice will be used during all drilling phases (e.g., setting of BOP; cementing of concrete between bore and protective pipe). Detailed BOP specifications are provided in Section 3.2.5. The detailed casing design and testing are described in Section 3.2.6. In addition, once the drilling rig to be used has been identified, Noble Energy and the drilling rig's owner will engage in a comprehensive inspection and testing of the rig's subsea BOP system to ensure compliance with the U.S. BSEE regulations. The inspection and testing will be witnessed and certified by a third-party surveyor. Noble

> Energy has committed to operating in Israel per BSEE regulations, unless superseded by MNIEWR regulations."

However, much of this information is either not provided or redacted.

Redacted parts of Drilling EIA, and 2017 Amendment include the following: details on drilling muds; condensate spill model total release volume; seafloor bathymetry at drill sites; geologic setting; seafloor morphology; well bore schematics; shallow stratigraphy of the Leviathan field; geohazards; seismicity; reservoir characteristics; reservoir gas composition; Cyprus A-2a well details; drilling plans and completion activities; casing design; well bore configuration and schematics; toxicological data; well barrier schematics; well production parameters; discharge chemicals; vessel information; BOP control; barite analysis; TCC report; bridging documents; shallow water flow contingency; well control handbook; expert opinion on increased WBM discharge; bathymetric maps at well sites; etc. Much of the 2017 Drilling EIA Amendment is redacted.

This is highly irregular and, for a project with such potential consequence and public interest, simply unacceptable. It is unclear at what point, or on whose behalf, the redactions occurred - the company, the government, or insurers (OPIC). If the company is responsible, then the Government of Israel has no way to determine the veracity of the company's safety assertions. If the company submits the information and the government then redacts it, then the public has no way to judge the safety assurances. Regardless, due to such extensive redaction, safety assurances by proponents cannot be independently confirmed. This must be remedied. Accordingly, I recommend the project approval be suspended until this information is made public, independently reviewed by relevant technical experts, and judged to be Best Available Techniques and Technology (BAT).

7.3 2011 Leviathan 2 Blowout

Regarding drilling risk, the 2011- 2012 Leviathan 2 well control event is instructive, but not adequately discussed. Section 1.13 (p. 114) of the Drilling EIA reports as follows:

> "During drilling of the Leviathan-2 well in May 2011, wellbore integrity issues occurred prior to drilling of the well's reservoir section. Due to these issues, the drilling rig was removed from the well. Following cessation of drilling operations (May 2011) and prior to the successful plugging (plug-and-abandonment) of the well in September 2012, there was a flow of formation water and subsurface sediments from the well….Findings from all post-plugging surveys conducted to date (November 2012 to January 2015) suggest that the plugging was effective (i.e., no evidence of a leak), and that conditions are gradually approaching normal conditions (i.e., decrease in size and salinity of caldera brine pool). It has been repeatedly shown in previous reports that all environmental impacts are minimal and highly localized

> within 200 m of the wellhead, and the area is showing signs of recovery. The effects of water and sand discharges appear to be minimal, having no indicators of toxic levels of contamination from compounds of concern."

Although there is little detail in this statement, and no further detail provided on this significant failure, it is evident that the well control and blowout response contingencies failed, and flow from the failed well continued for 16 months. This is an exceptionally long time to control a failed well, and indicates a failure in both well control and blowout response capability of the companies involved. Additionally, as the 2016 EIA (5 years later) reported that: "conditions are gradually approaching normal conditions," indicates the long-term nature of environmental impact from this well blowout. Further, this was not reported in the SLIP.

7.4 Blowout Preventers (BOPs)

Regarding the Blowout Preventer (BOP) to be used in drilling the high pressure, deepwater wells, the documents generally state:

> "Noble Energy and the rig's owner will engage in a comprehensive inspection and testing of the rig's subsea BOP system to ensure compliance with the U.S. Bureau of Safety and Environmental Enforcement (BSEE) regulations. The inspection and testing will be witnessed and certified by a third-party surveyor."

Given the 2011 failure of the Leviathan 2 well, the above assertion is questionable. And although the statement is encouraging, it needs far more detailed discussion, including independent verification, monitoring, and confirmation. For instance, documents should discuss the Independent Verification Organization that will be used for all aspects of the project, and their technical qualifications.

The documents do not recognize the inherent limitations of Blowout Preventers. A Blowout Preventer (BOP) is a critical safety system for subsea wellhead blowout control, but the documents should clearly recognize that a BOP is not a failsafe mechanism for sealing a well blowout. Numerous studies have documented the limited effectiveness of BOPs in sealing subsea well blowouts, but none of these are referenced.[28] Some of these studies report a BOP failure rate up to 45%. The residual risk imposed by this inherent failure rate should be honestly discussed, so that the public and government do not develop a false sense of security by the installation of a BOP on the seabed wellheads.

Further, the documents should cite and commit to comply with API Standard 53: *Blowout Prevention Equipment Systems for Drilling Wells,* which includes a rigorous testing and maintenance schedule for BOPs to be used.[29] Further on BOPs, they need to discuss the need for BOP and well function alarms to automatically default to close the well (activation of BSRs, EDS, general alarm, etc.), if specific alarms trigger but are not addressed in timely manner.

BOP activation methods include electrical transmission cable, acoustic signal, Remotely Operated Vehicle (ROV) intervention, a "deadman switch"/autoshear function, and an Emergency Disconnect System (EDS) on the drilling rig. Yet none of these critical BOP activation systems are discussed in detail. All of these BOP activation systems need to be independently inspected and tested regularly.

7.5 Blowout Response Plan

The documents do not present a rigorous well control plan, *Blowout Contingency Plan* (BOCP), a relief well plan, and secured contracts to provide these services. The BOCP must detail all technologies to be used, and verify that tests in expected conditions (at depth, temperature, and pressures expected at the seabed) have demonstrated the effectiveness of the well control response technologies. These should include a *containment dome* or *top hat* for initial response, a discussion of the pros and cons and methodologies for attempting a *top kill* of a blowout, a *capping stack* specifically fitted to the BOP to be used, and an adequate riser system and surface support vessels to collect hydrocarbons from a blowout. The BOCP needs to identify communications and logistics for deploying all equipment and support vessels necessary in a blowout response. This should include where the equipment will be physically located on standby, and how quickly it could be deployed to the Leviathan drilling sites.

The most reliable blowout control option is drilling a relief well from another Dynamically Positioned (DP) drill rig/ship, but such relief wells take time to complete. A relief well consist of drilling a secondary borehole near, or to intersect the failed well, pumping heavy mud down to overbalance the reservoir pressure, and/or perform a bottom-kill on the failed well. Sixty (60) days is a reasonable minimum estimate of the time it would take to complete a relief well at the Leviathan field. It should be noted that it took BP twelve (12) days after the *Deepwater Horizon* explosion just to begin drilling a relief well, and the relief well (at similar depths to Leviathan), was not completed until more than 4.5 months (137 days) later. However, over 95% of offshore well blowouts on the US OCS are stopped by surface (wellhead) intervention – muds, capping, BOPs, cement, etc. But a relief well should be drilled at the same time as surface intervention is attempted, particularly when the failed well bore is damaged, blocked, or cannot be accessed.

The documents do not provide a specific plan, or discuss a contract, for a rig to drill a *relief well* to perform a permanent bottom-kill of a blowout. This needs to identify what rig would be used to drill a relief well (e.g., the other rig engaged in simultaneous drilling the Leviathan field), its disconnect sequence and response time, and the time it may require to drill the relief well. As there will be two DP rigs on location drilling on an overlapping schedule for some of the drilling period, one drilling the well and one doing well completions, it is assumed that in a blowout emergency, the non-emergency rig would safely disconnect from its well and begin drilling the relief well adjacent to the failed well. This needs to be discussed in detail. As well, as drilling takes place from one vessel without the other on-site at the beginning of the drilling schedule, a relief well contingency must be identified.

The documents should list contracts Noble has in place with well control firms to assist in the intervention and resolution of well control emergencies. Such services include, but are not limited to, firefighting equipment and services, specialty blowout control equipment and services, directional drilling services, high-pressure pumping services, etc. Providers of such services include Boots & Coots International Well Control, Cudd Well Control, Wild Well Control, Safety Boss, Halliburton Energy Services, Anadrill Schlumberger, Baker Hughes INTEQ, Dowell Schlumberger, Baroid, and MI Drilling Fluids.

7.6 Pipeline Integrity Management

The documents fail to adequately detail a rigorous pipeline Integrity Management program for all offshore and onshore pipeline infrastructure.

Gas pipeline operators in Israel must be required to comply with international best practice standards, including those of the *American Petroleum Institute* (API), *American Society of Mechanical Engineers* (ASME), *British Standard Code of Practice for Pipelines: BS PD 8010 Part 2: Subsea Pipelines*, and *Norwegian Offshore Standard: DNV-OS-F101: Submarine Pipeline Systems*.

Under U.S. regulation, a *High Consequence Area* (HCA) for pipeline operation is defined as any area with high human population, navigable waterways, or an environment unusually sensitive to oil spills. It is recommended here that the Israel offshore and onshore regions be considered a *High Consequence Area* (HCA), requiring the highest pipeline standards possible.

The regulatory requirements for gas pipeline design, operation, and maintenance in the U.S. (Dec. 2003 U.S. Integrity Management in High Consequence Areas - Gas Transmission Pipelines), should strictly apply to all gas and condensate pipelines in Israel.[30]

The U.S. pipeline Integrity Management (IM) program requires the following of pipeline operators:

- Identification of all pipeline segments that could affect HCAs in the event of a failure;
- Development of a *Baseline Assessment Plan*;
- Risk Assessment, to identify all threats to each pipeline segment;
- Remedial actions to address integrity issues raised by the assessment;
- A continual process of monitoring, assessment and evaluation to maintain pipeline integrity;
- Identification of preventive and mitigative measures to protect HCAs;
- Methods to measure the program's effectiveness;
- A management-of-change process;

- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results.
- A communication plan

The API 1160 standard, published in November 2001, provides guidance to all API members (including Noble Energy) to implement the IM program, recommending that *all* pipeline segments are evaluated with a company's IM program. Clearly, all of this should apply to gas and condensate pipeline management in Israel.

This standard requires all operators to complete a Baseline Assessment Plan, including the following issues:

- Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
- Pipe size, material, manufacturing information, coating type and condition, and seam type;
- Leak history, repair history, and cathodic protection history;
- Product transported;
- Operating stress level;
- Existing or projected activities in the area;
- Local environmental factors that could affect the pipeline (e.g. corrosivity of soil, subsidence, climatic);
- Geo-technical hazards; and
- Physical support of the segment, such as by cable suspension bridge, etc.

Under the U.S. Integrity Management regime, an operator must regularly assess the integrity of their pipelines by several methods:

- Internal pipe inspection tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves (smart 'Pipeline Inspection Gauges', or `PIGs');
- Pressure testing;
- Assessing weld seam integrity, especially for Electric Resistance Welded (ERW) pipelines;
- Direct assessment of external and internal corrosion -- External Corrosion Direct Assessment (ECDA), and Internal Corrosion Direct Assessment (ICDA);
- Monitoring of cathodic protection;
- Other technologies that the operator demonstrates can provide an equivalent understanding of condition of the pipeline.

Further, U.S. Integrity Management law requires that pipeline operators must:

> "…continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other

> maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area."

A pipeline operator's Integrity Management evaluation and remediation schedule must provide for immediate repair conditions. Under this regime, a pipeline operator must:

> "…take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline."

A pipeline operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a High Consequence Area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to:

- Implementing damage prevention best practices,
- Better monitoring of cathodic protection where corrosion is a concern,
- Establishing shorter inspection intervals, and
- Providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls, etc.

Given the above, it is recommended that the Government of Israel immediately commission a comprehensive third-party Integrity Management (IM) assessment of all petroleum infrastructure in Israel, offshore and onshore, and require a rigorous Integrity Management program on all gas and condensate pipelines, existing and planned. This IM assessment should be conducted on all planned offshore gas development, including Leviathan, Aphrodite Block 12, Dalit, Karish and Tanin, Daniel East and West; and existing developments including Tamar, Mari-B and Noa, Hadera Deepwater LNG terminal, Shimshon Gas Field, and Aphrodite/Ishai. As well, all onshore petroleum infrastructure should submit to such an IM assessment.

7.7 Pipeline Leak Detection

A critical component in reducing pipeline ruptures and spill risk is a best available technology (BAT) leak detection system. The leak detection system should incorporate continuous monitoring using such technologies as line-volume accounting, flow meters, pressure transducers, rarefaction wave monitoring, real-time transient monitoring, acoustic emissions, fiber optic sensing, vapor sensing, and aerial surveillance of remote pipelines.

Externally based methods to detect leaking product outside the pipeline and include right-of-way inspection by pipeline patrols, ROV surveys on seabed pipelines, hydrocarbon sensing via fiber optic or dielectric cables. Internally based methods, also known as Computational Pipeline Monitoring (CPM), use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation.

International best practice requires effective alarm systems, and that the leak detection system must be sensitive, accurate, reliable, and robust. It was not possible to determine what leak detection technologies Noble intends to employ in its extensive pipeline system.

A robust pipeline leak detection system should include as many of the following characteristics (from API CPM 1995) as possible:

- Accurate product release alarming;
- High sensitivity to product release;
- Timely detection of product release;
- Efficient field and control center support;
- Minimum software configuration and tuning;
- Minimum impact from communication outages;
- Accommodates complex operating conditions;
- Configurable to a complex pipeline network;
- Performs accurate imbalance calculations on flow meters;
- Is redundant;
- Possesses dynamic alarm thresholds;
- Accommodates product blending;
- Accounts for heat transfer;
- Provides the pipeline system's real time pressure profile;
- Accommodates slack-line and multiphase flow conditions;
- Accommodates all types of liquids;
- Identifies leak location;
- Identifies leak rate;
- Accommodates product measurement and inventory compensation for various corrections (i.e., temperature, pressure, and density); and
- Accounts for effects of drag reducing agent.

For the Leviathan project, pipeline leak detection is to be achieved by continuous monitoring of arrival pressures and flow rates, a Production Management System to receive and monitor subsea sensor readings (continuous mass balance on entire production system), annual ROV survey, and a pipeline integrity assurance program. No further details of this systems-critical component were provided, and this needs considerably more detail. At a minimum, the frequency of ROV surveys of seabed infrastructure should be increased to at least monthly, not annually as proposed.

The Leviathan Drilling EIA states (emphasis added):

> "The risk of damage to the pipelines due to factors such as landslides, anchors in shipping lanes and trawler fishing *will be assessed* at all relevant locations along the route will also be considered in the safety risk assessment. Where significant risk is identified, preventative measures will be taken such as burying the pipeline or providing external shielding such as concrete coating, Uraduct® coating or concrete mattresses."

This assessment should have been completed and reported in these documents. As well, other pipeline safety design factors should be discussed, including pipeline wall thickness and spacing. As designed, seabed pipeline wall thickness will be slightly greater at free-span subsea channel crossings, but there is no detailed discussion of additional seabed pipeline design features to reduce risks of pipeline failure.

7.8 Additional spill prevention measures

Regarding the Dynamically Positioned (DP) drilling rigs to be used, which had not been selected at the time of publication of these documents (2016), there are many system-critical details that need to be reported and confirmed, including detail on the *Integrated Alarm and Control System* (IACS) on the drilling rigs, *Combustible Gas Detectors* (CGDs), electrical generator safety systems, fire suppression, and command structure on the rig, e.g., responsibilities and relationships between all project participants, including the rig owner, the captain of the vessels, Offshore Installation Manager (OIM), and all subcontractors.

The documents do not provide a discussion of the causes or specific responses to historic worst-case offshore blowouts, which indicates a lack of consideration for historic lessons learned. This is also required in the *2013 EU Drilling Directive*, and should be required for Leviathan.

It is unclear whether fire and explosion risk on the Leviathan Production Platform has been adequately assessed and mitigated via Front End Engineering Design (FEED). Explosion/fire on the LPP is a significant risk that could result in catastrophic consequences for human safety and the near shore environment. This must be clarified.

The documents do not present sufficient discussion of all inspection regimes, and training and qualifications of personnel, or third party expert review of the drilling plan.

The documents do not identify or commit to, as a risk mitigation measure, establishing an anonymous safety reporting capability ("whistleblower" provision), incentives and protections for personnel using such a system, and how each such report will be investigated. This is required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations*.

The documents do not present a complete casualty history for Noble or Ratio Oil's offshore drilling projects, as well as for the specific rigs to be used (which have yet to be identified). This information is necessary to evaluate the company's assertions regarding its safety management systems.

The documents do not adequately discuss Noble's *Safety and Environmental Management System* (SEMS), as is required in U.S. regulation (30 CFR 250 *Federal Register*, Vol. 75, No. 199, Oct. 15, 2010). This is also required in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). In this regard, the documents should detail the company's safety management structure, technical expertise, deepwater experience, analytical methodology to assess the performance of all safety system in event of multiple failures, and its overall *safety culture*. SEMS is a goal-oriented, performance based *Safety Case* approach, rather than the traditional prescriptive approach. It requires operators, contractors, and service companies to document their safety approach; work together to achieve safe drilling outcomes; formalize risk management procedures and responsibilities of all parties; establish clear communication procedures; establish a *Management of Change* (MOC) process; provide an independent assessment of well design, drilling, and completion; and a procedure to manage and incorporate evolving technologies. The *U.S. National Academy of Engineering* recommends a hybrid of prescriptive and performance based management regimes, and this should be discussed.

The documents fail to detail a rigorous substance abuse prevention program in all phases of the project, including for all subcontractors.

Regarding well completion and well-control monitoring, the Drilling EIA states (3.2.7):

> "Each well will be equipped with an SCSSV below mud line to prevent an uncontrolled release of hydrocarbons. In addition, each well will be equipped with a dual downhole pressure and temperature gauge for real-time downhole surveillance, included with chemical injection mandrels (CIMs) for mitigation against the potential risk of scale or hydrates."

Yet there is no more detail available re: the SCSSVs (Surface-Controlled Subsurface Safety Valves) or other downhole equipment to maintain well control during the operational/production phase. There is no discussion of the potential for SCSSV failure and loss of well control, or a robust contingency plan for such. This is a systems-critical issue, and must be detailed in the documents. Pressure transmitters in downhole equipment, including SCSSV systems, are known to fail from a variety of issues including plugging, leaks, trapped bubbles/gas pockets in liquid-filled impulse lines, trapped liquids in gas-filled impulse lines, electrostatic discharges, temperature-induced measurement errors, corrosion, and overpressures or vacuums.[31]

All of these potential failures must be addressed in detail, yet have not been in the documents reviewed. If subsea control systems lose surface control connectivity (such as after an explosion on LPP, or a break in the subsea umbilical connection), backup procedures would need to be employed quickly to cease gas and condensate production and release.

The documents do not identify all subcontractors to be used, and how they will be managed. In a drilling a complex deepwater prospect such as Leviathan, it is necessary to effectively manage several drilling subcontractors, service companies, and consultants, and staff simultaneously. For instance, in drilling the Macondo well in the Gulf of Mexico, BP employed at least eight (8) subcontracting companies for various components of the project. The relationship and communication between all corporate entities involved in a complex deepwater drilling operation is a safety-critical issue. The documents should clarify this relationship, which personnel have stop-work authority, and how and when this may be imposed.

The documents do not stipulate that an *Independent Well Control Expert* (IWCE), will be available and review the drilling procedures at all times during drilling, as well as a procedure for obtaining peer review and second opinions on various safety-critical decisions made before and during drilling. Such a system exists in the U.K., is required in the U.S. offshore Drilling Safety Rules (BSEE, 2012), and implied by the *2013 EU Drilling Directive* (EU, 2013). The independent third party expert should be a Registered Professional Engineer, whose qualifications are presented to and approved by government.

8. Selected Project Design – Platform vs. FPSO or FLNG

Nine conceptual design options were generally discussed in the Offshore Processing Scheme, Table 2.1, NOP 37H, as follow:

1. Direct Subsea Tieback – Full Processing Onshore
2. Direct Subsea Tieback - Full Processing Onshore with subsea pressure reduction
3. Direct Subsea Tieback – Full Processing Onshore with subsea pressure reduction or on a riser platform in territorial waters
4. Shelf Platform Subsea Tieback – Minimum Processing Onshore
5. Subsea Separation and Processing Onshore
6. Production to Mari-B Existing / Future Platforms and Partial Processing in Ashod
7. Shelf Platform Subsea Tieback – Maximum Processing Offshore
8. Shelf Platform Subsea Tieback – Full Processing Offshore, connection to NGTS pipeline offshore Hadera

9. Deepwater Development – Processing Offshore

"These nine concepts were then evaluated against a series of selection criteria and three were shortlisted for further evaluation in Stage 2 of the Planning Process": Cases 3, 4, and 7. Another option with minimal onshore facilities was also considered.

The document presents an inadequate explanation for why Case 9 "Deepwater Development – Processing Offshore" was declined as an option. In its Sept. 2014 document "Ratio Oil Exploration [1992]" document[32], Noble's partner Ratio Oil discusses the overall project concept for use of a Floating Production, Storage, and Offloading (FPSO) ship, and a Floating Liquefied Natural Gas (FLNG) option for the Leviathan project.

The NOP 37/H – Guidelines (1.6, Chapters A and B) provides a general discussion of some of the advantages and disadvantages of the FPSO/FLNG option. The document evaluates four different options in Case 9: Semi-Submersible Production Platform, Tension-Leg Platform, FPSO, and FLNG. However, these alternatives consider only seabed pipeline transmission of gas/condensate to shore, after initial storage and processing offshore -- the document does not consider use of shuttle LNG tankers or barges to transport LNG to shore facilities or export.

Several constraints to the offshore FPSO/FLNG option are raised in the document, some technical and some financial. Technical issues include potential condensation (hydrates) in seabed pipelines, engineering and durability of flexible risers between seabed wellheads and the FPSO/FLNG, etc. For all four alternatives, cost, time to build, and inability to supply gas to the local system are cited as impediments to the offshore alternative. In fact, the FLNG option can easily provide gas to the local gas system via shuttle LNG tanker or barge, or FPSO through seabed pipelines transporting dry gas to shore (as with the Karish and Tanin project), but this was not thoroughly evaluated.

The NOP 37/H document incorrectly states that FLNG is an "unproven technology." While such FLNG facilities are indeed new developments for deepwater, offshore gas fields, at least two are now operational - one in Malaysia, Petronas PFLNG 1[33], currently operating at the Kanowit gas field off Sarawak, Malaysia; and Golar's FLNG off Cameroon.[34]

Additional FLNG projects are now in development off China, Equatorial Guinea, and Australia, and others are presently in consideration. Shell's "Prelude FLNG" facility for the Prelude and Browse gas fields 200 km off South Australia (which is now on site) is largest floating structure ever built (488m x 74m, displacing 600,000 tons).[35] These FLNG facilities load and process all produced gas and condensate onto floating facilities over a deepwater offshore gas field, eliminating the need for hundreds of km of seabed pipelines to shore, near shore platforms, and other onshore infrastructure. The FLNG facility liquefies the gas, and then loads LNG onto shuttle tankers/barges for transport to markets onshore or export. As such, FLNG drastically reduces risk and impact to coastal resources.

As Shell states regarding its Prelude FLNG project off Australia:

> "FLNG technology offers countries a more environmentally-sensitive way to develop natural gas resources. Prelude will have a much smaller environmental footprint than land-based LNG plants, which require major infrastructure works. It also eliminates the need for long pipelines to land."[36]

And FPSOs (with gas/oil separation) have been used successfully for over 25 years for deepwater oil and gas fields, and there are presently over 200 in use globally. Some FPSOs are now in use at water depths far greater than Leviathan, including the *BW Pioneer* moored (via a disconnectable turret) in 2,600 m depth in the U.S. Gulf of Mexico.[37]

Further, the 2017 Energean *Karish and Tanin Field Development Plan* describes the relative advantage of an FPSO vs. seabed pipeline/onshore development option as follows: minimizes work to be conducted in the field, quicker development time, capital expenditure to first-gas, increased opportunities to export, tie-back of multiple 3rd party fields, reduced technical risk (e.g. hydrate formation in extensive seabed pipelines), additional product recovery from field, significantly reduced environmental footprint, and ease of abandonment after field is exhausted.[38] Regarding experience with FPSO technology, Energean's 2017 assessment states:

> "Use of a floating structure in the vicinity of the field is a much more common approach, one that has been mastered over the last 25 years. There are more than 20 floating units worldwide in water depths greater than the Karish field."[39]

Regarding environmental footprint of the FPSO vs. seabed/onshore option, Energean's 2017 analysis states as follows (*emphasis* added):

> "*Environmental footprint*: Using an FPSO located 75km from the Israel coast should result in the development having very low environmental impacts, substantially less than the other schemes considered. Environmental impacts should be lower during all project phases: construction, operation and abandonment. As no fixed platform is required and suction piles will be employed for the FPSO mooring system a small fleet of marine vessels will be required during construction/installation. This will result in low noise and pollution levels. The FPSO scheme also limits the potential for oil pollution resulting from pipeline leaks. *Hydrocarbon liquids are not transported to shore and hence the consequence of any spillage is significantly reduced*. The FPSO scheme also allows reservoir pressure energy to be employed more effectively reducing overall power requirements and hence emission levels. Importantly, the onshore and coastal project scope and hence environmental

> impact will be small. This is critical as not only will it ensure that environmental impacts are minimized but should aid in the obtainment of permits and hence support a fast-track project. The lowest CAPEX (capital expenditure) approach would have been to *treat all fluids onshore but clearly this would have had the most significant environmental impact* and hence was excluded."

To avoid construction delays for Leviathan, Noble could lease an FPSO, and tie-in to its seabed pipeline system now in construction to transport gas to shore, and ship condensate via shuttle tankers.

As far as could be determined, an FPSO/FLNG alternative for Leviathan was not further evaluated. *It is imperative that both of these options are reconsidered.*

The SLIP (p. 57) states (*emphasis added*):

> "Noble Energy assessed a variety of development and treatment options (i.e., onshore, offshore, sub-sea), including a Floating Production Storage and Off-Loading vessel (FPSO) with a Pressure Reduction Metering Platform, which was originally preferred, and a Fixed Platform...*There were no significant environmental differentiators or showstoppers identified across all of the viable options*. A fixed production platform was chosen, primarily in order to accelerate gas supply to the domestic market thus bringing redundancy to Israel's gas supply earlier."

This conclusion is clearly not supportable, as there are indeed dramatic environmental differentiators between the near shore platform and the FPSO/FLNG option.

It is inarguable that *near shore* risks and impacts from construction and operation of the project (noise, light, atmospheric emissions, marine discharge, visual/aesthetic impacts, socioeconomic impacts, etc.); risks of natural gas, condensate, diesel, MEG, methanol or other spills to coastal inhabitants and ecosystems; risk from fire/explosion on the LPP; and security/terrorism risk presented by the LPP and near shore infrastructure, etc.; would all be significantly reduced if, instead of the proposed LPP 10 km offshore, the project opted for an FPSO/FLNG facility 125 km offshore at the deepwater gas field. Accordingly, the selected LPP option should be reconsidered, in favor of Case 9: "Deepwater Development – Offshore Processing."

FPSO and FLNG, and LNG tankers will pose different risks, and these should be evaluated and mitigated as far as possible. But overall, the risk from an FPSO or LNG tankers carrying LNG from an offshore FLNG facility would be considerably lower than the near shore platform option.

From a security standpoint alone, the near shore platform option clearly poses far more risk than an FPSO/FLNG facility 125 km offshore (see discussion of this issue in Security Risk, Section 13, below). The LPP would likely be considered a high-value target for terrorist attack. Additionally, if hostilities were to erupt once again between, for instance, Hezbollah in southern Lebanon and Israel (as in 2006), a near shore gas processing platform close to the border (e.g., LPP) would likely be high on an adversary's target list.

As the Government of Israel is acutely aware, Hezbollah now possesses 130,000 – 150,000 rockets, including short, medium, long-range and M-600 ballistic missiles (with a range of 300 miles), mostly positioned along the southern Lebanese border.[40] While an FPSO/FLNG facility 125 km offshore would still be in range of long-range missiles, it would clearly be at less risk of this, and other threats, than would the platform only 10 km offshore. Additionally, an FPSO/FLNG facility should develop a contingency plan in the event of hostilities, in which it would close down all production and move off-site, out of range of hostile action. Such a response would be unavailable to the stationary LPP.

Further, the documents state that the actual rationale for declining the offshore FLNG alternative for Leviathan in favor of more traditional design (subsea pipelines to a near shore processing platform) was as follows:

> "…in order to accelerate gas supply to the domestic market thus bringing redundancy to Israel's gas supply earlier."

This statement confirms that commercial imperative to expedite gas deliveries was the main reason for selecting the platform option -- not minimizing environmental risk or impact. Cost was raised as an issue in all four alternatives offshore discussed in NOP 37/H.

Sources suggest that the total cost for the Shell's Prelude facility may be from $11 billion - $13 billion.[41] However, amortizing this cost over the expected 30+ year lifetime of Leviathan (which could gross over $100 billion), and other deepwater gas developments in the Eastern Mediterranean, FLNG becomes cost-effective.

Even though the Leviathan Production Platform (LPP) and seabed pipeline option has already been selected and are in development at present, as the project lifetime is expected to exceed 30 years, it is in the long-term interest of Israel to suspend the current platform development, and redesign the project as an offshore FPSO/FLNG facility. This would easily still provide domestic energy needs, as LNG shuttle tankers would transport gas and condensate to the Hadera deepwater LNG buoy, additional LNG buoys, other ports in Israel, or dry gas via seabed pipeline to shore. In fact, the FPSO/FLNG option would provide greater long-term flexibility for the project in meeting shifting markets and export opportunities.

Noble should explore options to sell the newly constructed LPP to another offshore gas project elsewhere.

Regarding the selected LPP location, three sites were evaluated, (TAMA offshore EIA

p. 193), Hadera, Havatzelet HaSharon, and Netanya, all along the same general depth contour (80 m - 90 m), about 10 km offshore. The EIA states: that "there is no significant difference between the three sites," and selected Havatzelet HaSharon, with the caveat that they still needed a "detailed survey of the seabed." However, it is noted that offshore platforms globally can be located in water depths to 500 m, yet the Leviathan documents do not discuss potential for locating the LPP further offshore, in deeper water. This should have been explored. Essentially, the further from shore a hydrocarbon platform or processing facility is, the better.

9. Condensate Spill Response

As it is light, volatile, and low viscosity, spilled condensate would be virtually impossible to contain and recover from the sea surface with conventional oil spill methodologies such as booms and skimmers. In fact, it is generally accepted in the international spill response community that there exists no containment/recovery methodology that would effective for condensate (or natural gas) spills at sea.

In a May 17, 2018 email reply to the author on the subject of response to condensate releases, Dr. Rob Holland, Technical Lead for *Oil Spill Response Limited* (OSRL) in the UK (the primary Tier III response contractor for most oil and gas operations globally, including Noble) stated as follows:

> "You are correct that in the majority of cases of gas or condensate releases then it's simply a matter of 'Monitor & Evaluate' with no direct intervention. Some condensates have higher wax content than others which can pose its own set of challenges once the fresh condensate has weathered at sea."[42]

It is important to note that there has never been a successful mechanical containment and recovery operation in response to a large condensate (or natural gas) release in the marine environment. As far as is known, none has even been attempted. There may be a possibility of using sorbent materials deployed to absorb small amounts of spilled condensate from surface and subsurface waters (e.g. newly developed polyurethane Oleo Sponge, sorbent booms and pads, etc.), and perhaps weathered condensate may lend itself to containment and recovery, but even these would have minimal effect on large offshore condensate releases. Thus for planning purposes, it should be assumed that none of an offshore condensate (or natural gas) release from Leviathan infrastructure would be recovered from the environment.

The assumption found throughout the Leviathan documents that condensate spills will behave similarly to oil spills is unfounded. Further, the assumption that chemical dispersants would be effective on a marine condensate spill is similarly unfounded. There is only minimal research into the effect of dispersants on condensate spills, with equivocal results.

It may indeed be possible to collect weathered, emulsified accretions on shore, and that should be explored. Shoreline contamination from a Worst Case Discharge of condensate could persist for months, if not years.

An *Oil Weathering Model* (OWM) should be conducted on Leviathan/Tamar condensate and natural gas. Input into the condensate OWM should include oil/emulsion film thickness, sea state, and sea temperature.

9.1 Oil Spill Contingency Plan (OSCP)

The documents assert that: "In the case of a spill, an emergency plan for the prevention of sea pollution will be executed. The program will include, *inter alia*:

- Use of dedicated equipment to deal with the spill event, at TIER 1 level;
- Periodic emergency drills according to the requirements of the Ministry of Environmental Protection;
- Operation of a local contractor to provide immediate response to a local spill;
- Operation of international contractors to respond to a regional event.
- The program will be based on the scenarios examined in both the OSCAR model and the MEDSLIK model, with respect to response times required to reduce the spread of the spill, and preventing its arrival at the coastline.
- The use of dispersants will be carried out in accordance with the Ministry's instructions, and subject to restrictions resulting from proximity to the coastline and marine reserves (water depth greater than 20 meters, distance from a reservation greater than 1 mile)."

The only OCSP available for review – Jan. 2018 "NEML Leviathan Field Installation and Construction OSCP – Tier 4" – does not constitute a sufficient operational spill response plan for all phases of the project, including drilling, production, and the LPP. The plan appears to focus mostly on inshore response scenarios, and even that is inadequate. No Shipboard Oil Pollution Emergency Plans (SOPEPs) or Emergency Response Plans were available for review, and there is no discussion of response equipment or capability at the offshore drill rigs or the LPP.

Condensate spill response assumptions in the OSCP (5.2) are listed as follows: "The general characteristics of the product associated with NEML operations favors dispersant over recovery. NEML's strategy will depend on many factors that will be situation dependent. In general, hydrocarbon release strategies may include the following:

- Dispersant Application
- Mechanical Agitation

- Mechanical Recovery
- Shoreline Protection
- Shoreline Cleanup/Recover
- Rehabilitation

The government and/or Noble should provide a *Material Safety Data Sheet* (MSDS) for Leviathan condensate, but the author has not been provided such. This is a standard requirement in the U.S. and Europe for all potentially hazardous chemicals produced, transported, or stored by industrial projects, and is also required in Israel. An MSDS should be provided for all hazardous substances involved in Leviathan.

9.2 Mechanical recovery

Mechanical recovery of sea surface oil spills consists of containment with booms and collection with various kinds of skimmers or sorbents.

But again, it is important to underscore the fact that spill response professionals do not generally consider condensate (or natural gas) releases at sea to be recoverable. In fact, even containment and response to large offshore *crude oil* spills is known to be generally ineffective, with usually less than 10% recovered. As example, recovery of *Deepwater Horizon* crude oil was only 3% of the total release volume, despite the largest oil spill response effort in history (with 47,000 response personnel, 7,000 vessels, costing over $14 billion). And recovery rate in the *Exxon Valdez* crude oil spill was about 7%.

As reported by SINTEF, condensates released on a calm sea surface may spread and form a thin film (less than 0.1 mm) of very low viscosity, and "the use of traditional mechanical recovery systems is assumed to have low efficiency on thin oil films."[43] However, after weathering for several days, there may be some solidification of condensate allowing containment with booms and collection with skimmers. But this solidification may be unlikely at high temperatures found off Israel.

For planning purposes, it should be assumed that a condensate or natural gas release at sea would be non-recoverable.

9.3 Dispersants

Regarding use of chemical dispersants, there is little evidence that dispersants would be effective on large offshore condensate or natural gas releases. Dispersants are a combination of a surfactant and organic solvent that lowers the interfacial tension between oil and water, resulting in emulsification and dispersion of surface oil into smaller droplets, increasing dispersion and bioavailability to natural hydrocarbon degraders.[44] They are usually applied via airplane, equipped with an *Aerial Dispersant Delivery System* package (ADDS-pack). In the 2010 Macondo blowout in the U.S. Gulf of Mexico, dispersants were also added at the deepwater wellhead. A contingency for wellhead dispersant application should also be developed for Leviathan.

Even with crude oil spills, chemical dispersants are known to be of limited effectiveness, exert a synergistic toxicity, and transfer of pollutant impact from the sea surface down into the water column. Dispersants are generally used on surface films greater than 0.05 mm – 0.1 mm thick, and they lose their effectiveness as oils weather. They are generally most effective when applied at a Dispersant to Oil (DOR) ratio of 1:25.

SINTEF reports laboratory tests that demonstrate some efficacy in use of dispersants on Sigyn (from an offshore field off southern Norway) condensate in calm (summer) conditions.[45] However, the window of time and sea/wind state within which dispersants may be effective is extremely narrow, the first few days at most. The SINTEF study that reported effectiveness of Dasic NS and Corexit 9500 on Sigyn condensate from 67%-100% did not establish a control, with no dispersant added, thus the dispersibility results are questionable.[46] Much of the reported dispersibility may simply have derived from mechanical wave action, not chemical dispersion.

From a practical response standpoint, it is extremely unlikely that large-scale dispersant application could be mobilized quickly enough to be effective on a major offshore condensate release. After only a one or two days, residual condensate on the sea surface would likely be too weathered to be dispersible.

And as surface application of dispersants transfers toxic hydrocarbon contamination from the sea surface down into the water column, their use should be avoided over shallow waters. Israeli dispersant use restrictions currently permit dispersant use in water depths greater than 20 m or outside 1 nautical mile of sensitive coastal habitats, and these rules need to be revised. *It is recommended here that dispersant use be prohibited in water depths less than 200 m, and/or within 10 miles of shore*.

If used on a condensate release, dispersants would increase the exposure of pelagic organisms to the water-soluble and dispersed fraction of condensate, thereby increasing impact in this component of the marine ecosystem. This was not addressed in the documents, but must be considered.

The Leviathan documents repeat the claim that: "*Expedited response from our oil spill response contractor and approval for the use of dispersant use is vital to successfully mitigating this event.*" As discussed above, the use of chemical dispersants in response to an offshore condensate (or natural gas) release has not been demonstrated to be generally effective. Indeed, even in response to crude oil spills the window for potential effective use of dispersants is very narrow, and generally only effective on fresh (un-weathered) oil (1-2 days out), and only with moderate wave/wind mixing, with winds between 10-20 knots.

Tests should be conducted to determine the potential efficacy of the planned dispersants (DASIC Slickgone NS and Sea-Brat 4) on condensate, both fresh and weathered. Otherwise, it should be assumed that chemical dispersants would not be effective on condensates that reach the sea surface, particularly as they weather. Furthermore, no chemical dispersants should be permitted to be used in waters less than 100 m depth, and closer than 10 miles from shore, or where surface currents may carry dispersants into waters shallower than 100 m or within 10 km of shore.

And even if laboratory tests demonstrate dispersant effectiveness, a dispersibility test kit should be used in any real-time condensate to confirm effectiveness on precise condensate surface films encountered. Again, it is unlikely that dispersants would be effective on a major offshore condensate release.

The operator should also examine the potential to inject dispersant into a wellhead blowout, as was done in the 2010 *Deepwater Horizon* blowout. This would include methodologies that might be employed, and the potential environmental effects of such deepwater dispersant application.

9.4 In-situ burning

The OSCP does not discuss *in-situ burning* (ISB) - a controlled ignition of surface hydrocarbon slicks - as a potential condensate spill response tool. It is not clear from the equipment list, referred to in the OSCP, what spill ignition or ISB equipment is on hand. An ISB plan must identify specific ignition strategies (Heli-torches, gels, etc.), herding agents, fire boom deployment strategies, and specific approaches to be used. It is thus indeterminate how in-situ burning would be considered or managed, particularly for a Tier III response. In a major blowout scenario, ISB will almost certainly be considered as an option for far-offshore response, and should be discussed in the plan. It must also be acknowledged that in many condensate spill scenarios ISB will remain ineffective.

In addition, the risk of fire/explosion with a surface condensate release must be carefully considered. SINTEF reports that Sigyn condensate poses a fire hazard during the first 2 hours after release, under calm (less than 2m/sec.) wind conditions, with a flash point below ambient sea temperature.[47] A similar risk may exist with an offshore release of Leviathan condensate. In particular, ignition may present significant risk if condensate is spilled onto the sea surface at the Leviathan Production Platform, thus jeopardizing the safety of the entire platform and seabed infrastructure control systems. This must be methodically considered in any spill risk/response scenario.

9.5 Additional OSCP Considerations

In OSCP section 5.3 Release Scenarios, the possibility of a well blowout is cited, but the only release scenarios discussed – operational failure, equipment failure, ship allision/collision – are discussed only in terms of the LPP. The possibility of a catastrophic well blowout offshore is not discussed in the response scenarios. This should be remedied.

Appendix 5 of the OSCP lacks sufficient transboundary contingencies and arrangements for spills that may drift to territorial waters and coasts of Lebanon, Egypt or Cyprus. As well, in section 8.1, there is no provision for stakeholder engagement in spill response exercises, or in actual response. Nor is there provision for surprise drills called by the government. These omissions must be remedied.

NEML's main response fleet and base is in Ashod, with additional rapid response facilities in Haifa and Hadera, yet the vessel particulars and equipment on hand are not itemized. Appendix 6 lists the installation vessels, yet few vessel particulars. Appendix 7 lists vessel contacts and eight response vessels, but no further information on their response capabilities. Appendix 8 lists the spill response equipment on hand. It is important that government authorities confirm the maintenance and operability of all response equipment with inspections and drills.

There is no wildlife response plan in the OSCP, which needs to be remedied. The Wildlife Response plan should include plans for hazing wildlife (seabirds, marine mammals, etc.) away from the front of a spreading plume of condensate or natural gas (surface or subsurface), and contain plans to capture and treat oiled wildlife.

Finally, the OCSP should discuss potential for a major condensate or gas release to contaminate seawater intake at desalination plants onshore (one is only 20 km from the LPP), and the potential for affecting drinking water quality. Studies have raised various technical concerns regarding removal of oil pollution from seawater prior to desalination.[48] In particular, these studies found that water-soluble components with small molecular size are difficult to remove. This risk should be examined by the Leviathan OSCP, and a contingency should be developed for monitoring and closing the intake to desalination plants if the potential for gas/condensate exposure presents itself in a spill.

Note again that the primary Tier II and III response contractor for Leviathan – OSRL in the UK – agrees with the author that there exists no effective response methodology for marine condensate spills. The OSCP should honestly admit such.

9.6 Vapor emissions above condensate spills

Depending on the precise conditions of release, condensates reaching the sea surface will undergo volatilization/evaporation into the overlying atmosphere, and disperse downwind. It is assumed that roughly 50% of a condensate spill will evaporate into overlying air as Volatile Organic Compounds (VOCs), which are acutely toxic. If the release is directly on the sea surface or from a shallow subsurface pipeline, a larger amount will evaporate. However, if the release is from a deepwater wellhead (1,600 – 1,700 m water depth) or pipeline, the evaporation percentage will be reduced, and amount remaining in the water column increased. Regardless, from the modeled release of approximately 175,000 bbls, it can be assumed that perhaps 85,000 bbls (12,500 tons) of condensate evaporation components (VOCs) will transfer into overlying air masses.

However, none of the documents reviewed contain a discussion of this atmospheric VOC plume that will develop over a condensate spill. Detail must be provided on this, including modeling the dispersion of the VOC plume as the condensate release spreads and weathers.

Some heavier residual components of a condensate release (e.g. decane, $C_{10}H_{22}$) can persist on the water surface, providing a continuous source of VOC emissions into overlying air. The U.S. CAMEO (Computer-Aided Management of Emergency Operations) chemical database reports that the Protective Action Criteria (PAC), PAC3 acute toxicity index for decane (e.g. a life-threatening atmospheric concentration) is 440 ppm, and a PAC2 (causing debilitating effects) is as low as 73 ppm.[49] EPA reports that heavier components of condensates (such as decane) generally exert greater toxicity. Decane exposure can cause the following symptoms in humans:

> "Contact with eyes may produce mild irritation. Contact with skin may cause defatting, redness, scaling, and hair loss. Ingestion may cause diarrhea, slight central nervous system depression, difficulty in breathing and fatigue. Inhalation of high concentrations may cause rapid breathing, fatigue, headache, dizziness, and other CNS effects."[50]

Regarding atmospheric emissions over condensate releases, Israeli scientists have conducted preliminary analyses using the US EPA ALOHA (*Aerial Locations of Hazardous Atmospheres*) computer simulation tool, predicting that in some spill scenarios from the Leviathan Production Platform (LPP):

> "Coastal inhabitants may be exposed to a toxic condensate cloud above the PAC2 Acute Exposure Guideline Levels for Airborne Chemicals as published by the EPA."[51]

Given the known acute toxicity of condensate components, this atmospheric plume that forms over a condensate release will pose risk to air-breathing organisms exposed, including seabirds, marine mammals, and humans. Although several Leviathan documents repeat the claim that this atmospheric plume would not present toxicological risk further than 200 m from the release point, the Environment Canada synthesis on Natural Gas Condensates (NGCs) concludes that:

> "Based on the available information, NGCs contain components that may persist in air and undergo long-range atmospheric transport."[52]

Regardless, any condensate spill response plan must include provisions to protect response personnel, the public, and air-breathing animals from the toxic atmospheric plume above the spill.

9.7 Spill tracking and monitoring

The Jan. 2018 Noble OSCP does not present plans or methodologies to track and monitor an offshore condensate spill, and this is a significant gap that must be remedied.

There are many procedures and technologies available for spill tracking that should be itemized and prepared in advance of project permitting.[53] These include aerial surveillance with digital cameras; aircraft-mounted infrared and ultraviolet sensors; multispectral satellite remote sensing; very high resolution radiometry satellite sensors; aircraft-mounted Synthetic Aperture Radar (SAR) and Side-Looking Airborne Radar (SLAR); shipboard observation; drift buoys; High Frequency (HF) and microwave Doppler Radar to map surface currents; water hydrocarbon sampling; hydrocarbon sampling buoy arrays; etc. For subsurface spill components, additional technologies should be discussed, including sonar, water column sampling, laser fluorosensors, geophysical/acoustic techniques, *in situ* fluorometric detectors, Remotely Operated Vehicles (ROVs), Autonomous Underwater Vehicles (AUVs), etc.[54]

The documents do not discuss the need to pre-plan a comprehensive *Natural Resource Damage Assessment* (NRDA, as it is known in the U.S.) with which to methodically document environmental damage from a large condensate or natural gas release from the project.[55] Such a comprehensive scientific damage assessment is necessary to determine the extent of ecological injury, inform the public and all stakeholders of the extent of injury, provide detailed information upon which to base claims to Responsible Party, and to formulate an environmental restoration plan. The documents should develop and discuss a pre-spill NRDA plan; a Rapid Assessment, Midterm Assessment; and Long-term Assessment plan; and NRDA organizational and management.

As well, the environmental monitoring plans proposed in the documents lack detail, and remain insufficient. It is suggested that environmental monitoring for all aspects of the project be funded by Noble and partners, but be conducted independently through IOLR (Israel Oceanographic and Limnological Research Institute), in cooperation with an Israel Offshore Citizens' Advisory Council (IOCAC, described in Stakeholder Engagement Plan section below).

10. Marine Discharge

10.1 Produced Water Discharge

Produced water (condensed water, formation water, and 'breakthrough' water) from the reservoir will flow in subsea pipelines along with produced gas and condensate to the LPP. Produced water will be separated and discharged at the LPP. Israel's MoEP reports (5/5/2018 letter from MoEP to Guardians) that the LPP produced water capacity will be only 800 m3 (8,700 bbl)/day, and is expected to discharge approximately 550 m3 (3,850 bbl)/day of produced water. The LPP will be fitted with a produced water treatment unit, consisting of two sorbent tanks and one backup tank. This unit is expected to bring discharged pollutant concentrations down to required limits: under 5 mg/L BTEX, and under 15 mg/L total hydrocarbons.

Still, produced water discharge should be conducted further offshore.

The TAMA Offshore EIA states (4.8.3):

> "…produced water is a complex mixture of organic and inorganic substances in a solution and in particulate form, with a water salinity ranging from almost sweet water to highly concentrated brines. Treated produced water contains dispersed oil, a wide range of natural substances in solution, and low residual concentrations of gas treatment additives such as corrosion and sedimentation inhibitors, MEG, and biocides. The natural substances in typical produced water also include small amounts of toxic substances such as heavy metals, aromatic hydrocarbons, alkyl-phenols, and radioactive substances (OGP 2002; OGP 2005; Neff et al. 2011)."
>
> "Of most concern are the three groups of micro-components: heavy metals (inorganic), and polycyclic aromatic hydrocarbons (organic), due to their toxicity and endurance in the marine environment, and alkyl phenols which are known to disrupt endocrine activity (Neff et al 2011; OGP 2005)."

Produced water toxicity derives largely from a combination of residual condensate, iron, ammonia, and hypoxia. Heavy metals in produced waters include mercury, cadmium, iron, copper, lead, nickel, and chromium, generally in concentrations between 1 mg/L and 4 mg/L.

Even with a predicted dilution factor of 10,000:1 at 100 m from the discharge point, it is advisable that produced water be discharged further offshore, off the continental shelf. A discharge pipeline should be extended at least 10 km offshore (total of 20 km offshore), at a minimum of 500 m depth, in order to discharge all produced waters further from productive shallow continental shelf waters. The physical oceanography in the Drilling EIA reports waters in the region are relatively isothermal and isohaline below 500 m. As well, fluorescence measurements report peak phytoplankton biomass from 50 m – 200 m depth. Thus, discharge at 500 m depth, below the thermocline and productive photic zone, would limit exposure of the shallow water shelf ecosystem to toxic discharge components.

Produced Water Reinjection (PWRI), in which produced water would be separated from the gas stream, piped back to the offshore field and reinjected into specific reinjection wells, was considered and declined in the NOP 37/H. While admitting that PWRI is technically feasible and would reduce impact to the marine environment, the option is declined as too costly (100 million Euros) and of little net environmental benefit. The document concludes that PWRI cannot be considered

Best Available Technology (BAT) due to their contention that the technical feasibility of deepwater PWRI for gas fields "cannot be considered as proven"; would cost 100 million Euros; and the impact of such discharge is "low and limited to the direct vicinity of the discharge point."

This should be reconsidered for all offshore gas projects, including Leviathan. BAT should not be judged by cost, but rather whether it indeed is BAT. Clearly, PWRI is BAT. And regarding the assertion that impacts would be low and limited to the direct vicinity, the multiyear impact of formation water released from the failed Leviathan 2 well should be considered. As discussed in the EIA, impacts from this 2011 release (of formation water, not petroleum) continued at least for 5 years.

However, even if PWRI is not adopted, the project should at least, as mentioned above, be required to construct a discharge pipeline from the LPP offshore at least 10 km (total of 20 km from shore), in order to discharge produced water off the continental shelf, in waters at least 500 m deep. This is easy to design and accomplish, and many coastal mining companies practice Deep Sea Tailings Disposal (DSTD) in this manner, discharging all tailings from coastal mines off the continental shelf in deep ocean waters. This is very cost-effective, and will minimize impacts to ecologically productive waters on the continental shelf.

10.2 Norway and U.S. Offshore Discharge Regulations

The U.S. Environmental Protection Agency summarizes offshore oil and gas discharge regulations in both the United States and Norway (2011).[56] Section 402 of the U.S. Clean Water Act authorizes the U.S. EPA to regulate marine discharges through the National Pollutant Discharge Elimination System (NPDES), requiring compliance with Ocean Discharge Criteria guidelines. Norway's Pollution Control Act authorizes the Norway Climate and Pollution Agency to regulate offshore discharges, including drilling fluids and muds, produced water, and other chemicals. Norway requires zero discharge of "environmentally hazardous substances," using Best Available Techniques, yet imposes a strict zero discharge requirement in more ecologically sensitive Arctic waters above 68° N.

For coastal facilities (within 3 miles of shore), U.S. regulation prohibits discharge of all drilling fluids, cuttings, and dewatering effluent (except Cook Inlet Alaska, where specific acute toxicity requirements must be met). For offshore facilities (outside of 3 miles), water based drilling fluids and cuttings, and oil-based cuttings are required to meet the acute toxicity standard, and discharge of oil-based drilling fluids is prohibited.

For produced waters, the U.S. prohibits discharge near shore (except Cook Inlet Alaska, where oil limits are 42 mg/L (ppm) daily, and 29 mg/L average over a month), as is required offshore. Israeli law similarly limits hydrocarbon discharge concentration to 29 mg/L average over one month. South of 68° N, Norway permits produced water discharge with components that "Pose Little or No Risk" (PLONOR), and less than 30 mg/L of oil monthly average. North of 68° N, produced water discharge is not permitted (except for "operational deviations," and then a maximum of 5% of produced waters may be discharged).

While Israeli requirements for total hydrocarbon concentration in produced water discharge are similar to those of coastal U.S. and Norway below 68° N, Israel does not regulate heavy metal concentration in discharge. Clearly, the highest standard is zero discharge, such as in Norwegian Arctic waters. It is recommended that the Government of Israel consider incorporating the Norway Arctic standard into Israeli regulation, prohibiting marine discharge of all drilling fluids, cuttings, and produced waters.

10.3 Emissions Monitoring and Reporting

It is unclear whether Israel regulation requires real-time emissions monitoring and reporting by offshore gas facilities, both atmospheric and marine. This must be clearly provided in regulation, as it constitutes best government/industry practice. In the U.S. Gulf of Mexico (where most U.S. offshore production occurs), the U.S. *Bureau of Ocean Energy Management* (BOEM) requires event-based reporting of air emissions from all offshore oil and gas facilities through its *Gulfwide Offshore Activity Data System* (GOADS).[57] This system requires operators to report air emissions through standardized computer software system. A similar monitoring and reporting system should be required by law in Israel for all offshore operators, for both atmospheric emissions and marine discharges.

11. Financial Liability

An important component of offshore drilling safety is an adequate liability regime that imposes sufficient financial liability for corporate negligence, in order to motivate effective safety management by the company. While there are international liability regimes covering oil tanker spills, bunker spills, and hazardous and noxious chemical spills, there is presently no international liability regime covering offshore oil and gas development. For now, this is left to coastal state jurisdiction.

While Israel is a party to the 1992 IOPC Fund Convention and the 1992 CLC, it is not party to the Supplementary Fund Protocol providing greater coverage for crude oil tanker spills; the 2001 Bunker Spill Convention (covering heavy bunker fuel spills); or the 2010 Hazardous and Noxious Substances (HNS) Convention (covering natural gas and condensate releases.)

Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations (EU, 2013) requires all member states to ensure that an offshore oil and gas operator:

> "…is financially liable for the prevention and mediation of environmental damage...from offshore oil and gas operations."

This should be the case in Israel as well. In this regard, Israel's national liability provisions for offshore gas development and transportation should be thoroughly reviewed and updated to ensure sufficient coverage of a Worst Case Discharge from any of the offshore gas projects. This can be done either through the international regimes, or more appropriately, through national legislation. Given that the BP spill in the Gulf of Mexico has cost BP over $61 billion USD[58], the Government of Israel should establish *unlimited liability* for offshore drilling projects (at least in cases of gross negligence). The government should also ensure that Noble, its partners, rig owners, and subcontractors are jointly liable, and have sufficient insurance coverage and/or bonding to cover all costs (including environmental damage) for a Worst Case Discharge. As well, Israel's criminal liability for gross negligence in industrial operations should be reviewed and enhanced as appropriate. This should be discussed in the documents.

The Government of Israel should establish a national *Oil Spill Prevention and Response Fund*, derived from a nominal (e.g., 0.10 Euro/bbl) assessment on all oil and gas produced or imported into the country, as many other governments have done. This Fund should be used by the government to enhance its oversight of oil and gas spill prevention and response preparedness, in particular its oversight capabilities regarding offshore gas exploration and production. The comparable fund in the U.S. is the *Oil Spill Liability Trust Fund*, derived from a $0.09/bbl fee, currently with a $5 billion current balance. [59]

12. CO2 Emissions

The documents predict the total CO2 (equivalent) emission from construction phase of the project will be 911,397 tons; from operations pre-2024 a total of 2,416,105 tons; and from 2025 – 2050 (project design life) a total of 15,416,825 tons. Thus, total CO2e emissions predicted from the project *per se* are estimated at 18,744,327 tons.

However, this estimate does not include emissions from the 22 Tcf of natural gas that will be produced by the Leviathan project. Using the US EPA conversion of 0.0550 ton CO2/Mcf gas, combustion of 22 Tcf of gas will emit approximately 1.2 billion tons CO2e. In addition, the project estimate likely does not include methane leakage from pipelines over the 30+ year lifetime for the project. These sources should be accurately and honestly reflected in project documents. The potential financial implication of future carbon pricing for this amount of emissions should be considered, and factored into the project's financial feasibility analysis.

The Government of Israel should establish a carbon tax of at least $60/ton CO2e (comparable to Norway) on all carbon emissions.

13. Security Risk

In general, the significant security and terrorism risk posed by the project, in particular at the LPP, has not been adequately addressed in project documents. Given the well-known security threats in the region, this is a significant gap in project risk assessment and must be remedied. In fact, the entire Israel Natural Gas Line (INGL) system should be subjected to rigorous and comprehensive security assessment and plan (if it hasn't already).

As currently designed, the Leviathan project presents significant security risk to the public and environment of Israel, including the potential for project infrastructure to be intentionally damaged or destroyed, leading to disruption of energy services onshore; mass casualties and/or health impacts; and disruption of commerce and public services. Security measures should be integrated into project design and construction. This issue deserves considerably more detail in project documents.

As discussed above (in Project Design, Platform vs. FLNG), a central issue in risk evaluation of the Leviathan Production Platform is the potential for hostilities between Hezbollah and Israel along the border with Lebanon (as in 2006). In such a situation, an FPSO/FLNG facility 125 km offshore is significantly less at risk than a processing platform only 10 km offshore. If hostilities were to ensue again, a near shore gas processing platform close to the border (e.g., LPP) would likely be high on an adversary's target list. As discussed above, this risk would be significantly reduced by selecting an FPSO/FLNG facility 125 km offshore for Leviathan.

Israel (and Noble Energy and its partners) now face significant security challenges, which will increase substantially as the new discoveries are developed.

The security risk posed by Leviathan (and other offshore gas fields of Israel) was discussed in 2011 by former Noble Energy official Abraham D. Sofaer, as follows[60]:

- Israel is already a victim of terrorist attacks in a volatile location. The development of natural gas adds another target for terrorists seeking to damage Israel's economy and infrastructure.
- The logistics of offshore exploration and development as well as the relatively limited requirements for terrorist attacks adds another layer of difficulty in maintaining security.
- Although the terrorist attacks on the oil and gas sector are a relatively small proportion of terrorist attacks overall, the data show that a significant number of attacks have occurred over the period 1990-2005. The number of attacks on the sector appears to be increasing in some countries. (Institute for Information Infrastructure Protection, "Trends in Oil and Gas: Terrorist Attacks")
- Platforms from which drilling and recovery operations take place need to be protected, along with transmission lines and installations in Israel or elsewhere to transport, liquefy and ship gas to purchasers. A stable gas

supply network is necessary for efficient markets, a growing economy and energy security.

- Types of possible attacks include the full range of threats posed by war and terrorist activities: rockets, explosives, torpedoes, bombings, suicide attacks from the air or sea, communications hacking, kidnapping of personnel, and hostage taking.
- Planning a terrorist attack on an unprotected oil platform is as simple as chartering boats, training divers, and providing them with the explosives required.
- Sabotaging transmission lines is even simpler than attacking platforms, with logistical requirements as low as obtaining shaped charges and the means for their delivery at any vulnerable point.

Sofaer noted that offshore platforms and related facilities have often been attacked by state and non-state forces. He went on to note that:

> "Options to reduce risk and maximize flexibility could include using a floating platform capable of processing gas into LNG. All security efforts would be concentrated at the drilling platform and FLNG facility, thereby reducing other, greater risks in natural gas production and transportation (Poten and Partners). Experts regard the risks of protecting vessels transporting LNG significantly lower than those of protecting pipelines and other stationary facilities. An FLNG facility is currently being constructed by Shell off the coast of Australia (to be complete by 2017), and contracts are in place for up to 10 more FLNG facilities throughout the world."[61]

As discussed above, an FLNG facility should develop a contingency plan in the event of hostilities, in which it would close down all production and move off site and out of range of potential hostile action. Such a response would be unavailable to the stationary LPP. At very least, Noble should develop a contingency plan for shutting in and evacuating the LPP in the event of serious threat during armed conflict.

Use of LNG shuttle tankers to transport LNG from an offshore FLNG facility to ports and offshore buoys introduces different risks into the project. These risks can be reduced and mitigated with standard maritime security techniques, including exclusion zones, varied (unpredictable) transit schedules, notices of sailing/arrival, intelligence, tug escorts, armed security, sweeps (divers, sonar, boarding), surveillance, crew background checks, ship security plans and officers, etc.[62]

On balance, from a security risk standpoint, risks posed by FLNG and LNG tankers would be significantly less than risks from a near shore platform.

Also in this regard, it is highly advisable for Israel and Lebanon to resolve the disputed maritime boundary region (330 mi2) between the two countries, along which Lebanon has recently offered offshore gas development tenders.[63]

A post-911 (2004) study by Sandia National Laboratory (U.S. Department of Energy) reports that risks from intentional damage from terrorist attacks to LNG infrastructure can be more severe than those from accidents.[64] Although the analysis focused on LNG risks, it can apply as well to all natural gas infrastructure, such as Leviathan. The Sandia study itemized intentional attack risks from vessel ramming, triggered explosion, insider takeover or hijacking, and external terrorist attack with explosive vessels (e.g. USS Cole), rocket-propelled grenades, missiles, or attacks by planes. It recommended several risk reduction and mitigation methods for each, including inspections, crew vetting, search and surveillance, improved intelligence, etc. All of these risks exist for elements of Leviathan, particularly the LPP.

The U.S. Transportation Security Administration (TSA) issued in 2018 its security guidelines for oil and gas pipelines, which provides a comprehensive guide for security on all components of the Leviathan project. [65]

The U.S. security guidelines recommend adoption of an overall Corporate Security Program, including the following elements:

1. Develop a corporate security plan;
2. Ensure sufficient resources, to include trained staff and equipment, are provided to effectively execute the corporate security program;
3. Ensure identified security deficiencies have appropriate financial resources allocated in the corporate budgeting and purchasing processes;
4. Assign a qualified primary and alternate staff member to manage the corporate security program;
5. Develop and maintain a cyber/Supervisory Control and Data Acquisition (SCADA) security plan, or incorporate cyber/SCADA security measures in the corporate security plan;
6. Develop and maintain security elements within the corporate incident response and recovery plan;
7. Implement appropriate threat level protective measures upon receipt of a pertinent National Terrorism Advisory System (NTAS) Bulletin or Alert; and
8. Notify TSA of security incidents meeting the criteria provided in Appendix B by phone or email as soon as possible.

The Leviathan project Security Plan should include a detailed system for security management and administration; security risk analysis and criticality assessments; access control measures; equipment maintenance and testing; personnel screening; drills and exercises; security incident procedures; response procedures in times of heightened threat levels; cyber/SCADA system security measures; testing and audits; and outreach.

A security risk assessment should detail facility criticality (primarily for near shore infrastructure such as the LPP and pipelines), not to exceed every 18months; threat assessments identifying known and unknown adversaries; a security vulnerability assessments (SVA) identifying all potential security weaknesses; risk assessments based on threat, vulnerability, consequence; risk mitigation countermeasures; and ongoing adaptive risk management.

Security measures for project offshore and onshore facilities include adoption of enhanced, site-specific security measures (bulletins and alerts, etc.); measures to impede unauthorized access; 24/7 intrusion detection and monitoring; personnel identification; personnel background screening; equipment maintenance and testing; personnel training.

Cybersecurity is a particular concern, and must be addressed. The U.S., the National Institute of Standards and Technology (NIST) has developed a *"Framework for Improving Critical Infrastructure Cybersecurity*," which provides general guidance relevant to Leviathan (and the entire INGL system). In addition, several other security guidance documents from the U.S. should be considered for the Leviathan project, including the following:

- American Chemistry Council, *Guidance for Addressing Cyber Security in the Chemical Industry*
- American Gas Association (AGA) Report Number 12, *Cryptographic Protection of SCADA Communications, Part 1: Background, Policies and Test Plan*
- American National Standards Institute (ANSI)/International Society of Automation (ISA) – 99.00.01 – 2007, *Security for Industrial Automation and Control Systems: Terminology, Concepts, and Models*
- ANSI/ISA– 99.02.01 – 2009, *Security for Industrial Automation and Control Systems: Establishing an Industrial Automation and Control System Security Program*
- American Petroleum Institute (API) Standard 1164 *Pipeline SCADA Security* ANSI/API Standard 780, *Security Risk Assessment Methodology for the Petroleum and Petrochemical Industries*
- U.S. Department of Commerce, National Institute of Standards and Technology (NIST), *Framework for Improving Critical Infrastructure Cybersecurity*
- U.S. Department of Commerce, NIST, Special Publication 800-82, *Guide to Industrial Control Systems (ICS) Security*
- U.S. Department of Homeland Security, Office of Infrastructure Protection, *Risk- Based Performance Standards Guidance: Chemical Facility Anti-Terrorism Standards,* May 2009
- U.S Department of Energy, Office of Electricity Delivery and Energy Reliability, *Energy Sector Cybersecurity Framework Implementation Guidance,* January 2015
- U.S Department of Homeland Security, *Transportation Systems Sector Cybersecurity Framework Implementation Guidance,* June 2015

14. Stakeholder Engagement

The Stakeholder Engagement Plan (SEP) outlined in project documents (in particular Appendix 2 of the SLIP), is clearly insufficient. Noble states:

> "Noble Energy is committed to establishing and maintaining transparent, respectful and regular engagement practices to understand and manage stakeholder concerns and interests. These practices are above and beyond the engagement activities managed by Israeli government agencies as a part of the permitting processes."

First, given the extensive amount of redaction of systems-critical information in project documents, as well as the failure to publicly report the 2011 Leviathan 2 exploration well failure, the above assertion is questionable.

More importantly, the Stakeholder Engagement Plan relies on traditional passive engagement, which for a project of such complexity and potential consequence is insufficient.

Passive engagement conducted by the proponents to date (cited in the 2016 SLIP) provides simply that:

> "…third parties potentially affected by project development are provided with opportunities to review project information and provide comment."

The oil and gas industry's conventional passive stakeholder engagement process provides thousands of pages of detailed, technical documents for public review and comment, public hearings, public relations campaigns, etc., but this is known to be an insufficient method for obtaining authentic, informed public engagement.

For a project with the technical complexity, risk, and potential consequence to the public interest of Israel, a more deliberate SEP process must be established. For that, I recommend establishment of the *Israel Offshore Citizens' Advisory Council*.[66]

Large-scale resource development projects such as Leviathan (Tamar, and other offshore gas developments) generally receive insufficient oversight by, and engagement with, civil society. While industry and government may provide *transparency*, this in itself does not constitute effective civil society engagement. Members of the public often have insufficient time, financial ability, and technical expertise to engage effectively in complex resource development and policy issues such as Leviathan.

There can be an overwhelming amount of information available regarding projects such as Leviathan, much of it technical and unfamiliar, and even multiple projects and policy issues intersecting simultaneously, making it difficult for citizens to assimilate pertinent information and provide informed comment. While outside technical experts can conduct site-visits and consultancies to provide their technical review and recommendations, if there is no standing citizen capacity to follow through on the recommendations, such processes may have limited impact.

And in the absence of effective public engagement, corporate and government vigilance can weaken, complacency increases, environmental and social standards decline, and risks increase. Such insufficient oversight, lower standards, and complacency can result in acute and catastrophic results; such as oil spills; long-term, chronic environmental degradation; and social tension, mistrust, litigation, and even violence between local people and industry.

To correct this problem, local civil society stakeholders need to be directly involved in the review and oversight of resource industry operations that potentially affect their lives, in particular extractive industries such as oil, gas and mining. And to effectively engage, citizen stakeholders need their own organization with sufficient funding, staff, authority, broad representation, and independence.

Additionally, as the Government of Israel is both financial beneficiary and regulator of the project, it has an internal conflict of interest in providing effective oversight.

14.1 *Israel Offshore Citizens' Advisory Council*

Thus, it is proposed here that the Government of Israel require the establishment of an *Israel Offshore Citizens' Advisory Council (IOCAC)* as a pre-condition for final government approval of the Leviathan project. Modeled loosely on the two oil oversight citizens' councils in Alaska (www.pwsrcac; www.circac.org), as well the *Shetland Oil Terminal Environmental Advisory Group,* or "SOTEAG", in Scotland (www.soteag.org.uk/), the IOCAC would provide structured, non-binding, informed public advice, oversight, and engagement with all offshore petroleum development in Israel's EEZ.

It is proposed that the Israel Council be guaranteed a budget of approx. $5 million USD/year, either from government resource revenues from the projects, or directly from the offshore petroleum industry (e.g., Noble and its partners). By comparison, our PWS RCAC receives approximately $4 million/year from the owners and operators of the Trans Alaska Pipeline System Marine Terminal in Valdez Alaska. As proposed, the Israel Council would have a broader mandate, and cover the entire offshore EEZ of Israel. Thus, a budget of $5 million/year seems appropriate.

The Israel Council should be comprised of all major stakeholder constituencies potentially affected by offshore industry – e.g., fishing, aquaculture, conservation, tourism, women, youth, science, and local communities. Properly structured, the IOCAC will become the *eyes, ears, and the voice* for local citizens regarding large-scale petroleum development in Israel's EEZ, and augment government and industry oversight of the offshore projects.

The Council should have a Board of Directors representing all major stakeholders, paid staff for day-to-day operation, and sub-committees as appropriate to its mission. The broad mission of the IOCAC would be to enable citizen stakeholders to ensure the highest standards of environmental and social responsibility of all offshore industrial projects and/or all industrial activity in Israel's EEZ. Its goal is to reduce the deleterious environmental and social impact and risk of resource development, and enhance communication and engagement between civil society, industry, and government.

Specifically, the Council should provide oversight, advice, and advocacy on issues such as where to permit additional development, *Best Available and Safest Technology* (BAST) standards, biodiversity conservation, risk assessment and accident prevention, response preparedness, liability standards, environmental monitoring, biodiversity offsets, invasive species control, social impact mitigation programs, transport routes and methodologies, regulatory reform, government revenues and taxes, waste management, remediation and restoration, labor practices, human rights, human health, and so on. The Council should review and submit written comments on all existing and proposed project operations. This can include legislation, regulations and permits, and industry policy, procedures, and financial matters.

At the request of its Board or committees, the IOCAC should commission independent scientific studies, consultancies, and reports on issues of interest or concern to its stakeholders. This research should contribute to the factual basis of the council's policy recommendations to industry and government.

The Council will provide an on-going, structured mechanism for greater communication, collaboration, and trust between citizens, government, and offshore industry, and should reduce industry's environmental impact, risk, and footprint. The citizens' council will not substitute for effective governmental oversight, but will complement and enhance such. The establishment of this proposed Council is fundamental to industry's "social license to operate," genuine corporate social responsibility, citizen empowerment, environmental justice, government legitimacy, and sustainable development. As such, the citizen council will provide long-term benefit to the public, government, and industry.

15. Government Revenue - Israel Permanent Fund

While outside the scope of work for this review, another important consideration that must be addressed is a sufficient government royalty/taxation regime for hydrocarbon development, and the need to save a portion of these non-renewable revenues in a national hydrocarbon revenue savings fund. This is done by several other governments around the world, including Alaska, Alberta (Canada), and Norway.[67] As hydrocarbon reserves are finite, so is the revenue they provide.

Thus, in the interest of its citizenry (present and future), the Government of Israel should establish a sufficient taxation regime for offshore gas development, collecting at least 50% of gross revenue from the projects; and setting aside at least 50% of these government hydrocarbon revenues in an Israel Permanent Fund, perhaps modeled after the Alaska Permanent Fund (now worth over $65 billion USD). A portion of the government revenues from gas development should be committed to subsidies for renewable energy in Israel.

16. Conclusion

Given the above substantive concerns, it is the author's respectful recommendation that the Government of Israel immediately suspend permitting for the Leviathan project, pending satisfactory resolution of all issues discussed herein.

In particular, the project should be redesigned to eliminate the near shore Leviathan Production Platform (LPP) and extensive seabed pipeline infrastructure, opting instead for an FLNG facility offshore at the gas field and use of shuttle tankers to deliver LNG and condensate to Israel and other markets; or an FPSO. An offshore FPSO/FLNG option would dramatically reduce near shore risks and impacts of the project.

The most environmentally responsible option for Leviathan development is for Noble to design and construct an FLNG facility, using LNG and condensate shuttle tankers. Alternatively, in order to avoid construction delays, the company should consider leasing an FPSO for initial Leviathan development (as it does at its Aseng oil and gas field off Equatorial Guinea), and tie-in to its seabed gas pipeline system (now in construction) to transport gas to shore and the INGL system. Noble should sell the newly constructed LPP to another offshore gas project elsewhere.

As well, many systems-critical technical details are either not reported, or redacted from the project documents. This must be remedied before permitting.

Again, while the above review focuses on the insufficiencies of the Leviathan documents, it is offered respectfully, and in the sincere hope that it will assist Israeli civil society, the Government of Israel, the companies, and potential lenders better understand the risks involved in the project, the potential effectiveness of proposed risk mitigation measures, and contribute to informed decisions. This review is offered in recognition of Israel's laudable goal of securing energy independence.

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Appendix I – Author Biography

Summary of relevant professional experience of author, Professor Richard Steiner, Anchorage Alaska (www.oasis-earth.com):

The author has worked extensively in the field of marine oil spill prevention, response, damage assessment, restoration, and policy around the world, advising governments, industry, the U.N., NGOs, and the public on environmental issues of offshore oil and oil spills, as summarized below:

- Alaska – Professor and marine conservation biologist at University of Alaska from 1980 – 2010, stationed in the Arctic; Prince William Sound; and Anchorage. In early 1980s conducted workshops in Arctic communities re: risks of offshore oil development; participated in 1989 Exxon Valdez oil spill -- advised emergency response, helped develop the U.S. Oil Pollution Act of 1990, co-founded the Prince William Sound Science Center, initiated establishment of the Regional Citizens Advisory Councils (RCACs), and proposed settlement of government / Exxon legal case and use of funds for habitat protection; continued public outreach on offshore oil / environment issues. Helped found and served as Facilitator of *Shipping Safety Partnership* to reduce risk of ship casualties in Aleutians and Arctic.
- Russia – Co-Principal Investigator for project on oil spill prevention and response on Sakhalin Island; served as foreign technical expert on public review commission for the Siberia Pacific Pipeline project; taught oil spill workshops in Russia Far East, Siberia, and Western Russia; advised Russian government and Duma on oil royalty and taxation issues; and served as oil spill expert on IUCN/Shell Independent Scientific Review Panel to review the Sakhalin II project and its threat to the critically endangered Western Pacific Gray Whale.
- Kazakhstan and Azerbaijan - Worked with civil society groups to enhance oil sector and government transparency, and enhance government take of oil revenues.
- Africa – Nigeria, worked with Nigeria Ministry of Environment, NGOs, and state governments in assessing and mitigating damage from oil development in Niger Delta; advised Delta State governor; and served as expert witness in lawsuits re: environmental damage from oil; organized and directed Natural Resource Damage Assessment of oil spills in Niger Delta. In Mauritania, worked to enhance citizen involvement in offshore oil sector oversight.
- Pakistan - Developed and served for Pakistan Environmental Protection Agency and UNDP as Chief Technical Advisor for first comprehensive oil spill Natural Resource Damage Assessment in a developing nation in 2003 – 2004, for Tasman Spirit oil spill in Arabian Sea.
- Lebanon - During Israel/Hezbollah war of 2006, advised the government of Lebanon on issues regarding the Jiyeh oil spill, including response and damage assessment; briefed the Israeli government and U.S. Embassy in Tel Aviv on the spill.
- China – Conducted rapid response mission to Dalian oil spill, advised Chinese NGOs and media on spill, 2010. Advised NGOs, media, and governments re: Sanchi condensate tanker disaster in East Sea, 2018.
- Gulf of Finland – Conducted workshops in 2005 on behalf of U.S. State Department on oil spill prevention, response, damage assessment, and restoration in Finland, Russia, Estonia.
- Canada – Advised Indigenous tribes in B.C. re: risks of oil transport and pipelines proposed to north coast.

- U.K. – Advised Shetland Island government, media on Braer Oil Spill, 1993.
- U.S. – Conducted several projects in U.S. re: oil spill prevention and response, including for State of Hawaii, advised groups in Gulf of Mexico BP spill in 2010, many speaking engagements re: environmental risks of oil, etc.
- Belize – Conducted rapid assessment of environmental aspects of oil development in Belize for citizen's coalition (2011).
- Japan – Conducted oil spill prevention, response, and impact workshops around Hokkaido Island (2004).
- Spain/Canary Islands – Served as technical expert for Fuerteventura Council, Canary Islands, in review of deepwater drilling proposal in Canary Islands 2013.
- New Zealand – Provided expert witness affidavits for offshore oil exploratory drilling legal cases, 2012 and 2015.
- Norway/Svalbard – Co-principal scientist on research cruise re: offshore oil drilling off Svalbard Norway, Barents Sea in 2014.
- Other - Authored dozens of technical and popular publications on environmental risks of oil, including international manual on environmental damage assessment and restoration after large marine oil spills for UNEP and IMO, commented regularly to media on oil risks, etc.

Appendix II – Hydrocarbon Influence on the Marine Environment
(cited here verbatim from TAMA Offshore EIA, pp. 250-255)

The impact of presence of hydrocarbons in a marine environment may be acute or chronic.

Acute toxicity – immediate short-term impact of a single exposure to a toxin
Chronic toxicity - ongoing exposure to a toxin

Hydrocarbons' acute and chronic toxicity to marine organisms depends on several factors:

1. Hydrocarbon concentration and length of exposure
2. Bioavailability and persistence of the specific hydrocarbon
3. Ability of the organism to accumulate and metabolize the hydrocarbons
4. Ability of the hydrocarbon metabolites to interfere with vital physiological processes (growth, reproduction, survivability)
5. Narcotic effect on neural conductance

A study conducted in Australia under controlled laboratory conditions (Neff et al., 2000) tested chemical and physical changes in various oils as a result of evaporation and the impact of these changes on their chemical composition and toxicity to marine organisms. Condensate was one of the tested substances. Study results show that in a fresh contamination, MAH (monocyclic aromatic hydrocarbons) are the most substantial contributors to acute toxicity, and when weathering processes have had some time PAH (polycyclic aromatic hydrocarbons) become more prominent contributors.

PAH toxicity depends among other factors on molecular structure. In general, the light aromatic hydrocarbons (including MAH) are considered acutely toxic but not carcinogenic to marine organisms. Heavy aromatic hydrocarbons, on the other hand, are not acutely toxic but several of them are known carcinogens (see Canadian Council of Ministers of the Environment, 1999). The high acute toxicity of light aromatic hydrocarbons is mainly ascribed to their being highly water-soluble. In a hydrocarbon mixture (such as that in condensate) overall acute toxicity is the cumulative product of the individual components' toxicity. Narcotic effects of hydrocarbons are mainly ascribed to light volatile hydrocarbons.

Considering that the tested scenario in the present survey outlines an extreme incident with damage to a condensate storage tank and a one-time dumping of liquid into the sea, and based on the information regarding the chemical properties of the liquid (high content of light hydrocarbons) we estimate that the expected impact on organisms in the shore area will be classified as acute.

<u>Environmental impact</u>

The impact of hydrocarbon pollution, including that of condensate, on the marine environment varies depending on a large range of factors, the main ones being: the exact chemical composition of the spilled liquid, weather conditions at the time of contamination and afterward, properties of the receiving medium (water, sand, rock), and the composition of the exposed population. To predict the nature of the expected trauma to some habitat as a result of hydrocarbon contamination it is advisable to review studies conducted in the field in the wake of similar contamination incidents, and find relevant information from lab experiments. Pertinent data must be cross- referenced regarding impact on similar taxa, even if the geographical regions are different.

<u>Open sea environment</u>

Condensate contamination originates in the open sea environment so the contamination is expected to travel on the water surface. At this point weathering processes will be in their early stages and the most impacted will be organisms that inhabit the open waters and the upper portion of the water column. Most impacted organisms at this stage are populations of plankton, fish, and birds that come into contact with the water, but also marine mammals and sea turtles are at risk of exposure.

<u>Plankton</u>

Phytoplankton and zooplankton, including larval forms of many invertebrates as well as fish eggs and larvae have a central role in primary production in the marine environment. A study conducted in Australia under controlled laboratory conditions (Neff et al., 2000) that tested toxicity of condensate and three other oils has shown that acute toxicity of the two light oils was higher than that of the heavy oils in all six species of organisms that were tested (2 species of fish, an elongated-abdomen decapod, a mysid, a sea urchin, and sea urchin larvae). Tracking the impact of pollution on plankton populations in the open sea is difficult to unachievable, so it is impossible to rule out long-term effects of such pollution which may manifest in harm to the adult population of certain species (as a result of injury to the larval stages).

Birds

Seabirds are considered to be highly vulnerable to hydrocarbon pollution because they come in direct contact with the substances floating on the water surface. Species that concentrate at the water surface and/or dive in search of food are at high risk of injury. Main causes of death on exposure to pollution are: drowning, starvation, poisoning, and loss of body heat caused by feathers being covered in tar. Although there have been attempts to clean birds who were affected few survive the process, and it transpires that their chances of reproducing successfully are small. Detailed information regarding the bird population of the Carmel beach area is available in Appendix N, attached below.

Marine mammals and sea turtles

Marine mammals and sea turtles breathe air and must come up to the surface to do so. In case of a large oil slick, these creatures will be exposed to chemicals' toxic fumes particularly if they are exposed during the spill's first hours. Inhaling toxic fumes may injure the respiratory system and cause irritation to a varying degree. Organisms may also be exposed to oil pollution through feeding and skin contact. Digesting chemicals after consuming contaminated organisms or accidental ingestion of oil may injure the liver and kidneys, cause anemia, immune depression, reproductive dysfunction, and even death.

Terrestrial environment on the shore

The slick's final destination is the beach, where it will land on a sandy or a rocky bed (see below). The sandy environment in the shallows and in the surf zone is a homogenous habitat (with relatively few ecological niches) and it has a low stability which dictates a relatively small variety of species compared to rocky habitats and sandy habitats in deeper water. Nevertheless, pollution reaching the sandy beach will largely contain a mixture of hydrocarbons at advanced weathering stages. As noted earlier, at this point we know that the mixture's acute toxicity can be ascribed to PAHs. We further know from a study conducted following the Exxon Valdez disaster that exposing fish eggs to degradation products of the spilled oil caused developmental and genetic damage as well as death (at exposure levels of 0.4-

0.7ppb PAH). Other studies have demonstrated developmental damage also in invertebrates when exposed to lower concentrations of hydrocarbons.

Organisms that inhabit the beach such as the tufted ghost crab (Ocypode cursor) and crabs that live on the wave-washed swash zone such as Gastrosaccus sanctus) can be expected to suffer harm from exposure to pollution, as are birds that feed in this area by feeding on contaminated organisms. Sea turtles may also be exposed to pollution impact in their laying areas; this poses a hazard to adult turtles, egg development, as well as survival of the young turtles.

If hydrocarbons are also present on the sandy bed, then the benthic population of the soft bed, meiofauna in particular, will be adversely affected by the presence of PAHs. Experiments conducted in closed systems have found that PAHs have an inhibitory effect on physiological processes also in microalgae. When present in sediment, PAHs may also affect the composition of species in the benthic community by boosting the numbers of resistant species such as nematodes, an effect that could cascade up the food chain.

Intertidal zone

The rocky intertidal zone's vulnerability to hydrocarbon contamination and its ability to recover is directly related regional geomorphology. Shore structure and degree of exposure to wave energy in addition to the factors noted above are also significant (see also the table of oil spill sensitivities, below). On a rocky beach that is exposed to wave energy the slick's retention time will be limited and recovery is expected to be rapid. If a rocky beach has an irregular front, with many small bays and areas that are protected from wave action, the slick can be expected to get trapped in the protected areas causing ongoing damage and slowed recovery. Under the condensate pollution scenario, physical coating and asphyxiation of organisms by heavy hydrocarbons is not expected, but toxic effects from water-soluble components are a possibility. These effects may be short-lived (a few hours) but in protected areas like small bays and tidal pools such as those found in the abrasion platform area may increase the water's retention time (with toxins present) and therefore also organisms' exposure time to toxins. Organisms from a wide variety of groups are vulnerable, algae, clams, crabs, worms, sponges, bryozoa, cnidaria, fish, and others (see Appendix N). Note that sedentary organisms that are incapable of movement will be harder hit than motile organisms that can move away from the contamination. Data gathered in studies of intertidal zones in North America with similar biological land-cover seem to indicate that despite these organisms' sensitivity to hydrocarbon contamination, almost complete recovery was observed within approximately two years. At the same time, there is a risk of harm to key species, and harming these could set in motion longer term changes.

It is worth noting that weather conditions at the time the contamination reaches the shore and afterward has significant bearing on its impact on biota. A violent storm accompanied by a stormy sea will mix and disperse the contamination and will probably lessen organism exposure (mostly sedentary ones) to toxins. A calm sea and a dry heat wave can cause extended exposure to toxins; if this is accompanied by an extreme low tide, damage to the rocky intertidal zone organisms will be lethal.

Impact of pollution on the Carmel beach area

The shore between Maagan Michael and Geva Carmel beach is composed of Kurkar islands off the shore, sandy beach areas, rocky beaches, and abrasion platforms of the most complex and valuable along the Israeli coast. These areas, some of which have been declared nature reserves (Dor island and Maagan Michael nature reserve, Habonim beach reserve) and some are slated to become nature reserves in the future (Dalia River estuary, and the area from Givat Michal at Dor to Taninim River, along a 7km section of shore) include a great variety or animals and plants in many different habitats (see in detail Appendices M and N of this document). In case of a condensate leak from a storage tank in the southern compound (Compound 2) where the gas treatment platform is planned, contamination will make landfall between Maagan Michael and Geva Carmel within 12 to 24 hours (see model results above). If there is a leak incident in the northern compound (Compound 1) the contamination is expected to make landfall between Neve Yam and Dado beach (on the southern outskirts of Haifa). Also along this shore segment are rocky and sandy habitats as well as sea turtle laying grounds, as listed in Appendix M. Marine organisms are expected to suffer harm from the time the substance is discharged to sea and up to an unknown time post- discharge. Initially, the dominant source of acute toxicity will be MAH, and as the contamination advances and weathering progresses, PAH concentration will increase and they will become the chief contributors to toxicity. Organisms first in line to be hurt are those inhabiting the top water column (plankton, fish, marine mammals, and sea turtles) and the surface (birds). Next, as the contamination nears the shore, Dor and Maagan Michael beach islands will be impacted (rocky bed habitat and bird population) as well as the rocky area opposite Neve Yam (leak scenario in Compound 1) and immediately afterward the sandy shore between Maagan Michael and Dor, and the area north of the Atlit fortress on to Dado beach in Haifa, and the rocky area/abrasion platforms of Dor/Habonim nature reserve and a little further north of there, and the area adjacent to Atlit (leak scenario in Compound 1).

It is important to note that due to the absence of closed bays that are protected from wave energy on the sandy shoreline between Maagan Michael and Dor beach, hydrocarbon compounds are unlikely to be found accumulating in the sediment. However, even if sedimentation occurs following decomposition and adhesion to particulate matter, the sedimentary material is expected to continue mixing into the body of water and be carried away with the currents.

It is difficult to estimate the degree of injury, capacity for recovery, and duration. All these vary with the species, weather conditions, and biological processes (reproduction, recruiting, nutrition). We must also emphasize that until actual production from the submarine reservoirs begins and the exact composition of the condensate becomes known, treatment methods remain unknown. Condensate contamination is expected to harm various organisms (as listed above) as it progresses toward the shore. Among these are invertebrates as well as vertebrates from a wide range of systems and habitats in the open sea, on the islands near the shore, and on the shore in highly valuable sandy and rocky areas. Note that significant portions of the shore between Maagan Michael to the south and Dado beach to the north are nature reserves, and additional sections are slated to be included in future nature reserves.