39-390 S CLAIMS TRIBUNAL

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Case No. 39 Date of filing: 29. Jun 89

** AWARD - Type of Award ______________
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** CONCURRING OPINION of Mr George H. Aldrich

- Date 29. Jun 89
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R/12

CASE NO. 39

CHAMBER TWO

AWARD NO. 425-39-2

PHILLIPS PETROLEUM COMPANY IRAN,
Claimant,

and

THE ISLAMIC REPUBLIC OF IRAN,
THE NATIONAL IRANIAN OIL COMPANY,
Respondents.

CONCURRING OPINION OF GEORGE H. ALDRICH

I concur fully in the Award in this Case with one exception, its evaluation in Section IV C 5(c) of the degree of risk of post-1979 coerced revisions in the Joint Structure Agreement ("JSA"). I also believe it appropriate to note that I have serious reservations about the alternative valuation method used in paragraphs 159-165 of the Award, although, in deference to the wishes of the Chairman, I do not oppose its inclusion in the Award for the limited purpose of confirming the conclusions reached by the Tribunal through its adjustments to the results of the Claimant's Discounted Cash Flow ("DCF") analysis. Finally, in an annexed analysis, I offer an explanation of the reasoning applied by the Tribunal to reach its conclusions with respect to the quantity of crude oil that could reasonably have been expected in September 1979 to be available for recovery during the remaining twenty years of the JSA.

1. Risk of Coerced JSA Revisions

I believe the Award seriously overestimates the extent to which a buyer in September 1979 would have reduced the price it would have been willing to pay for the Claimant's JSA interests because of the risk that Iran might in the future insist upon further revisions of the financial terms of the JSA to prevent any increase in the profits received by the owner of those JSA interests. The Award, both in Section IV C 5(c) and in paragraph 163 when it considers its alternative valuation approach, appears to assume that Iran would ensure that the Second Parties under the JSA receive none of the real benefits of any future price increases. This I consider unreasonable and not warranted by the evidence.

The Award does recognize that the "stabilization clauses" would not be thought to have lost all effectiveness and that the changes in financial terms previously insisted upon successfully were both demanded by all OPEC members, not just Iran, and were impelled by extraordinary and dramatic oil price "shocks", not simply gradual price increases over time. Those changes shifted huge "windfall" profits from the oil companies to the OPEC members. Despite these unique circumstances, the Award concludes that in September 1979 a serious risk would have been perceived that further revisions would successfully be demanded in circumstances where real prices were predicted to rise gradually by 35 percent in ten years and by 63 percent in twenty years. I believe this grossly overestimates the risk that a reasonable buyer could have been expected to foresee on the basis of the experience of the 1970's. Moreover, the Award makes no effort to square its conclusion with the fact that neither the substantial price increases between the date of the 1977 revisions and September 1979 nor those that occurred in 1980 and 1981 led to OPEC demands for further contract revisions. The 1977 changes left the Claimant with approximately a two percent share of the profits of JSA operations. Further limiting adjustments in that arrangement, in the absence of drastic increases in the price of oil, (a) could not reasonably be implied from the experience of the 1970's, (b) would, in my judgment, violate the reasonable expectations of an investor to share in the profits of its investment, and (c) would almost certainly not be accepted by investors who, like the Second Party to the JSA, have access to arbitration.

Consequently, I conclude that, given the Tribunal's conservative findings in Section IV C 3 with respect to the future oil prices that would have been foreseen in 1979, the value of the Claimant's JSA interests in September 1979 would have been reduced, but only modestly, by virtue of the perceived risk that a buyer might encounter irresistible future pressures to modify the JSA in ways that could reduce the anticipated future profitability of its JSA interests.

While it is difficult to quantify this disagreement, it leads me to conclude that the Claimant should be awarded compensation for its JSA interests approximately ten million dollars more than that determined by the Award. Nevertheless, I concur in the Award with respect to this determination in order to form a majority.

2. The Alternative Valuation Method

In view of its conclusion that the Claimant is entitled to compensation for the fair market value of its JSA interests at the date they were taken by the Respondents, the Tribunal quite properly accepts the Claimant's DCF analysis as relevant evidence of such market value. Any reasonable buyer would have made such an analysis of an income-producing asset such as this. The Tribunal also quite properly analyzes for itself the quantities of recoverable oil, prices, costs, and risks and makes, as a result, appropriate adjustments to the Claimant's DCF conclusions. Consequently, the Tribunal can be confident that its valuation conclusions are soundly based and fair to all Parties.

In these circumstances, I regret that the Award proceeds unnecessarily to "confirm" its conclusions with respect to valuation by reference to what it calls an underlying asset valuation approach, particularly as such a valuation method was never discussed by the Parties, and the relevant evidence for using such a method was neither requested nor introduced.

3. Analysis of Recoverable Crude Oil

Voluminous evidence was presented by the Parties and their chosen experts concerning the amount of oil available for recovery from the off-shore areas involved in this Case. That evidence presented the Tribunal with the necessary, but complex, task of determining reasonable estimates of recoverable oil, by both primary and secondary recovery methods, from the two IMINOCO fields -- the Rakhsh and Rostam fields -- and within those fields from the several reservoirs which each contained. The Tribunal evaluated this evidence at length and reached its conclusions on each reservoir as a result of a detailed analysis. Ultimately, the Tribunal decided, however, to include in the Award only its broad conclusions and not the analysis itself. Therefore, I present that analysis, as I understand it, as an annex to this Opinion to lay to rest any concerns that the Award's conclusions on this issue might have been arbitrarily reached or resulted from only superficial examination of the evidence.

Dated, The Hague
29 June 1989

George H. Aldrich

George H. Aldrich

ANNEX TO CONCURRING OPINION OF GEORGE H. ALDRICH

Analysis of the
Quantity of Recoverable Crude Oil

a) The Rakhsh Field

1. The Rakhsh Field had three producing reservoirs, the Arab C, the Shuaiba, and the Mishrif. Of these, the most prolific producer was the Arab C.

(1) Rakhsh Arab C

2. The Claimant asserts a total recovery of 140,350,000 barrels of oil from the Rakhsh Arab C Reservoir between 1979 and 1999, of which 58,904,000 barrels would be from primary recovery and 81,446,000 barrels from secondary recovery.[1] The Respondents counter with a projection of a total recovery of 52,953,000, of which 39,377,000 would be from primary recovery and 13,576,000 from secondary recovery.[2]

(a) Primary Recovery

3. Both the Claimant and the Respondents base their primary projections on a July 1977 IMINOCO model study -- the final IMINOCO-approved depletion study -- entitled "Case

[1]Corresponding figures for the Claimant's expert, Core Lab, are a total of 119,522,000 barrels, of which 69,217,000 would be from primary and 50,305,000 from secondary recovery.

[2]Corresponding figures for the Respodents' expert, ECL, are a total of 48,460,000 barrels, of which 39,660,000 would be from primary and 8,800,000 from secondary recovery. ECL
(Footnote Continued)

12". The Claimant asserts that Case 12 predicted results in 1978 and 1979 which were closely matched by actual performance in those years. Consequently, only minor adjustments, according to the Claimant, had to be made to the Case 12 model for it reliably to predict primary recovery for 1979-1999. Core Lab, however, believes that the Claimant's forecast was too conservative because it did not allow for the maintenance of higher reservoir pressure through natural water influx.

4. The main technical differences between the Claimant and the Respondents are that the Respondents contend that the Case 12 results had to be adjusted substantially downward for (1) the unpredicted closure of well ARK-7, which the Parties agree was closed ("shut in") in 1978 because of erratic flow, and (2) the Respondents' assumption that production from well ARK-9, the most prolific producer, would cease at the end of 1981 because of an increasing water-cut percentage (percentage of water produced with oil) that the Respondents estimate would exceed 20 percent by mid-1980.[3]

5. With regard to well ARK-7, the Respondents implemented their adjustment by subtracting 4,125,000 barrels of projected well ARK-7 oil production for 1979-1984 (the remaining well life according to Case 12), or approximately 13% of projected Rakhsh Arab C production for these years. The Respondents assert that they based their adjustment on the assumption that the unpredicted closure of well ARK-7 in

(Footnote Continued)
has also put forward figures for primary and secondary recovery of, respectively, 39,988,000 and 16,610,000 barrels.

[3]ECL's own forecast "left [ARK-9] on production until the end of 1983" when water-cut would reach 25 percent.

1978 was the cause of the 12.4% difference between actual production in 1978 and that predicted by Case 12 for 1978.

6. However, Core Lab has convincingly shown, in an argument unrebutted by the Respondents or ECL, that most of the reduced actual production for 1978 was caused by fewer than normal production days as a result of political events, during November and December 1978. Had production during those months been similar to the average for the rest of 1978, then actual production for 1978 would have been only 5.6% less than the model, which suggests that other wells were making up for much of the loss of production from well ARK-7. Consequently, the Claimant's reduction by about 5% of production predicted by Case 12 between 1979 and 1984 appears reasonable.

7. With regard to well ARK-9, the Respondents note that it began to produce water in June 1978, increasing to about 5% water-cut by the end of that year. "As a result . . . oil production rate of ARK-9 dropped to 2942 BOPD and 1978 BOPD during November and December of 1978 respectively." The Respondents conclude that the water-cut trend of well ARK-9 would reach 20% by mid-1980 after which time production would become problematic and flow would cease by the end of 1981. Consequently, the Respondents subtracted production expected from well ARK-9 after 1981 from the Case 12 model.

8. The Claimant indicates that, again, the reduced production rate in November and December of 1978 was due to significantly fewer than normal producing days during that time. Indeed, the Claimant asserts that test oil rates for well ARK-9 in November and December 1978 were 4034 BOPD and 4460 BOPD, respectively. The Respondents have not contested these assertions. Moreover, the Tribunal was presented with little convincing evidence that the relative steepness of either the Respondents' or ECL's predicted increase of water-cut percentage, whether extrapolated from 1978 or

1979, was at all justified by the data available.[4] No evidence was presented as to why well ARK-9 could be predicted to produce so much water. When Mr. DeBoer of ECL was asked at the Hearing what normal engineering practice would be in the event that a prolific producer such as ARK-9 were to die, he was unable to comment because "You have to know the reason why it particularly dies or produces that water cut and I don't want to speculate on that basis." Moreover, at the Hearing, Dr. Connaughton from Core Lab observed that, if well ARK-9, the most prolific producer, had started producing a significant amount of water, a pump would have been installed rather than letting the well die.

9. Beyond the technical support for the Claimant's position on primary recovery, substantial contemporaneous evidence, presumably available to a buyer in 1979, lends further support to the Claimant's predictions of about 59 million barrels of primary recovery. From the Second Party report of 1975, for example, a forecast of primary recovery for the period 1979-1994 of about 60 million (60,299,000) barrels of oil could be derived from the data in that report.[5] A Geology and Reservoir Evaluation Report presented in June 1976 by the Claimant's Supervisor of Development Geology in Iran, Mr. Beverly Geho (the "Geho Report"), forecast (as of 1 April 1976) the recoverable primary reserves at 81,237,000 barrels. As the production from 1 April 1976 to 31 December 1978 was in fact 19,708,525 barrels, the perspective in 1979 on the basis of the Geho

[4]As reported by Core Lab, tests in 1978 showed that the water-cut percent declined in the last third of the year, while in 1979 the water-cut leveled off at under 5% by August 1979.

[5]The report contains a forecast of total recovery as well as data on incremental secondary recovery from Arab C. Primary recovery is obtained by subtracting predicted secondary recovery from total recovery.

Report would have been for 61,529,000 more barrels of primary recovery. The Case 12 Model of July 1977 forecast primary recovery from 1979 to 1999 of 61,107,000 barrels. This study had been reviewed and approved by the IMINOCO Development Committee in June 1977 at a meeting attended by all parties. The minutes of the meeting reflect agreement as well with the cumulative [total production since the very beginning of the reservoir's production] Arab C primary oil recovery prediction of the Case 12 study for 128 million barrels by 1 January 2000, a number referred to again by IMINOCO in October 1978.[6] As the cumulative Arab C primary production by the end of 1978 is known to have been almost 66 million barrels, again the perspective in 1979 on the basis of recent IMINOCO reports would have been reasonably to expect primary production from 1979 to 1999 to be in the region of 62 million barrels. In view of all the evidence, it appears reasonable to conclude that a buyer in 1979 would have estimated that approximately 58,000,000 to 60,000,000 barrels of oil were recoverable from this reservoir during the remaining JSA period through primary recovery.[7]

(b) Secondary Recovery

10. The Parties agree that the difference in their projected timing of the commencement of secondary recovery is by far the greatest reason for the difference in their secondary recovery forecasts. The Claimant asserts that it based

[6] IMINOCO referred to it in a document suggesting amendments to the 1358-62 preliminary Five Year Plan. The amendments were suggested to reflect comments expressed by NIOC at a meeting held several days before.

[7] Core Lab asserted that primary recovery would have been greater on the basis of certain historical data. The Tribunal has no evidence before it corroborating Core Lab's findings or confirming that such findings would have been reasonably reached in early 1979, especially in the face of the contemporaneous evidence just cited.

its secondary recovery projections of more than 81 million barrels on a July 1977 IMINOCO model study entitled "Case 13X" which was approved by the IMINOCO Development Committee in June 1977. The Claimant stated that the Case 13X study was itself based on the assumption that water injection would begin in July 1979 with full scale injection in July 1980. The Claimant based its forecast in the present Case, however, on the assumption that water injection would begin in July 1980 with the project fully operative in July 1981. Consequently, according to the Claimant, the sole adjustment made to Case 13X was to shift its rates ahead by one year.

11. As a preliminary matter, ECL persuasively indicated -- a point not disputed by the Claimant -- that, in fact, Case 13X actually presumed water injection starting in July 1978 with full scale injection in July 1979. Thus, assuming that secondary recovery is not materially affected by a two-year delay, the adjustment to be made to Case 13X would be to shift its rates ahead by two years, rather than one year, resulting in a slightly reduced secondary recovery prediction of 80,683,000 barrels.[8]

12. The Respondents reject the notion of secondary recovery, asserting that there had been a history of Second Party delaying tactics with regard to secondary recovery, that there had been only a limited amount of testing, that no budget had been approved by the IMINOCO board for such projects for 1979 or thereafter, that future approval of such projects in the budget would require NIOC's 50% vote in the affirmative and that, with the circumstances of the Iranian Revolution, such "practically abandoned" secondary recovery operations could not have been foreseen in the near

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[8]Core Lab forecasted less secondary recovery as a result of adjusting the Case 13X model so as to compensate for the same stronger natural water drive that it found should have increased the Claimant's primary forecast.

future. The earliest possible date for the implementation of secondary recovery in Rakhsh Arab C, they argue, would have been July 1990 with full operations by July 1991. Oil production rates from that date would have to take into account the 12 years elapsed since the Case 13X presumed starting date of 1978.[9]

13. The evidence is overwhelming that very substantial quantities of oil would be recoverable from the Rakhsh Arab C reservoir through secondary recovery and that a reasonable investor in 1979 would have considered secondary recovery by water injection in Rakhsh Arab C to have been imminent. Studies -- with very positive findings -- concerning secondary recovery in this reservoir had been undertaken since 1972. While delays evidently occurred for various reasons -- including the unavailability of drilling rigs and, as the Respondents have pointed out, the Second Party's reluctance to approve new funds because of its dispute beginning in 1975 over the imposition by Iran of higher taxes and royalties -- there is no evidence that the secondary recovery project underway in 1978 and 1979 would in mid-1979 have seemed likely to be scrapped.[10] That evidence demonstrates NIOC's consistent concern that secondary recovery projects should progress apace. And the post-1977 history, covered below, reveals the keen interest by all parties in rapid commencement of secondary recovery in Rakhsh Arab C.

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[9]ECL used the Respondents' assumption concerning the timing of water injection start-up in two assessments resulting in forecasts of approximately the same relative order of magnitude as the Respondents.

[10]The question of the impact on the value of the Claimant's interests in the JSA of the risk that could have been perceived in mid-1979 -- that changed policies of the new Islamic Republic could result in NIOC's seeking some further delay in this secondary recovery project -- are dealt with separately in the Award, since this analysis discusses only the amount of oil technically recoverable.

14. In June 1977 IMINOCO's Development Committee met and approved the latest model work, consisting of a history match summary of January 1977 (approved by NIOC in March 1977) and other studies including Case 13X. The Development Committee recommended that Case 13X begin to be implemented by the drilling of the first two water injection wells. NIOC concurred with the Committee's recommendations on 11 July 1977. Indeed, on 25 June 1977 NIOC had written a letter to Mr. Trampini, the Managing Director of IMINOCO, enclosing general guidelines for preparing the 1978-82 Five Year Plan. Those guidelines called for rapid implementation of secondary recovery projects and specifically for the diligent pursuit of the objective of Rakhsh Arab C water injection[11] by the second quarter of 1979. In October 1977, Mr. Trampini sent NIOC a tentative five-year plan apparently incorporating those guidelines. In December, the IMINOCO Board (after the settlement of the fiscal dispute) approved commencement of the project. In February 1978, all the parties met and apparently finalized the 1978-82 five-year plan. That plan reveals that capital spending on the Arab C project in 1977 had been over 2.3 million dollars.

15. In April 1978 Mr. Khalili of NIOC sent IMINOCO guidelines for the preparation of the 1979-1983 Five Year Plan. Those guidelines called for the implementation of full-scale injection by no later than the first quarter of 1980. In May, AGIP was commissioned to complete the engineering work. Drilling began for water injection wells RK-16 and RK-17 in June and September 1978, respectively, and was completed in August 1978 and February 1979, respectively.

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[11] NIOC placed this project in the category "Approved Projects - Firm Timing and Scope (forming basis for further development of plans)."

16. At the end of September 1978, the parties to the JSA met to review IMINOCO's Five Year Preliminary Plan and Program for 1358-1362 (21 March 1979-20 March 1984). In ensuing comments on 3 October, NIOC suggested added detail on the Rakhsh Arab C secondary recovery project. The Second Party's comments of 16 October 1978 asserted that the project was expected to be commissioned within the fourth quarter of 1358 (i.e., by 20 March 1980), in accord with NIOC's guidelines of April 1978. The Five Year Preliminary Plan indicated that more than 12 million dollars of capital expenditure had been made in 1978 on the Rakhsh Arab C secondary recovery project.

17. On 19 December 1978 the IMINOCO Board of Directors met. The Managing Director noted that no comments had been received from NIOC on the economics of the Five Year Plan or on the 1358 budget. As the first quarter 1979 budget had not yet been finalized, the Board approved the Managing Director's proposal to authorize IMINOCO to proceed only with normal expenses and with the Rakhsh water injection project. The approval of this type of ad hoc continuing resolution was repeated at the next meetings of the Board on 4 April, 8 May, and 19 June 1979.

18. On 27 March 1979 AGIP reported on the status of the project. It noted that engineering work should be completed by the end of September 1979, with drilling to be resumed in February 1980 and start-up foreseen for the end of March 1981. A letter of 11 April 1979 from IMINOCO to NIOC indicated an intention to resume drilling in December 1979, ahead of AGIP's schedule. When AGIP, on 19 June 1979, next reported on the project's status, it noted that 67% of the engineering work had been completed and foresaw project completion in April 1981.

19. On 15 April 1979, at the annual shareholders' meeting of IMINOCO, the total cost of the Rakhsh water injection

project was estimated at 40 million dollars, with secondary recovery estimated at 80 million barrels of oil. Other sources contained estimates of the same order of magnitude. The Second Party's Report of 1975, for example, estimated secondary recovery of 66 million barrels for the 17-year period 1978-1994. The 1977 Development Committee, apparently on the basis of Case 13X results foresaw recovery of 85 million barrels. Case 13X itself forecast 84.7 million barrels from 1979 full-scale injection to 1999.[12] Finally, NIOC's own comments of 3 October 1978 on the Five Year Preliminary Plan apparently forecast secondary recovery of 70 million barrels of oil by the end of 1999.

20. In light of the foregoing events -- including substantial progress on all phases of the technical work, extensive preliminary planning and budgeting, specific expenditure authorization on Rakhsh Arab C both just before as well as after the success of the Iranian Revolution, capital expenditures in excess of 14 million dollars, and sizeable predicted secondary recovery by a number of sources extant in 1979 -- it seems abundantly clear that the only reasonable expectation in September of 1979 would have been for secondary recovery in Rakhsh Arab C to occur along the lines set forth by the Claimant,[13] although with some delay inevitably resulting from the Iranian Revolution and that a buyer of the Claimant's JSA interests would prudently have estimated approximately 70,000,000 barrels of oil would be recoverable as a result during the life of the JSA.

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[12] The correction to Case 13X to reflect the Claimant's two-year delay in implementation of Case 13X results in a figure of 80.6 million barrels.

[13] Indeed, in an interview in August 1979, Dr. Movahed, advisor to the chairman of NIOC, confirmed that "secondary recovery programs will definitely go ahead. They are very much needed." XXII "Middle East Economic Survey", No. 45 (27 August 1979).

21. Thus, it appears reasonable to conclude that the total oil recoverable through both primary and secondary methods from Rakhsh Arab C would reasonably have been estimated by a buyer in 1979 at approximately 128,000,000 to 130,000,000 barrels.

(2) Rakhsh Shuaiba

22. The Claimant asserts that a total of 73,905,000 barrels of oil from the Rakhsh Shuaiba Reservoir would have been predicted in 1979 for recovery between 1979 and 1999, of which 39,960,000 would be from primary recovery and 33,945,000 from secondary recovery.[14] The Respondents counter with a projection of a total recovery from this reservoir of only 21,754,000 barrels, of which 18,956,000 would be from primary recovery and 2,762,000 from secondary recovery.[15]

(a) Primary Recovery

23. The Claimant obtained its projections by pump calculation forecasting which involves calculations basing well production rates on the fluid-lifting capacity of the pumps. Certain assumptions were made including the presumed addition of two new producing wells in 1981 allegedly planned in conjunction with secondary recovery, a minimum required bottom hole flowing pressure of 100 psi, a maximum per well rate of 5100 barrels of fluid per day for one of the new wells and for two of the three existing wells in Rakhsh Shuaiba which were producing at stable rates in 1979 (Wells

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[14] The corresponding figures for Core Lab are a total of 69,008,000 barrels, of which 33,288,000 barrels would be from primary and 35,720,000 from secondary recovery.

[15] The corresponding figures for ECL are a total of 17,278,000 barrels, of which 16,038,000 would be from primary and 1,240,000 from secondary recovery.

ARK-13, ARK-14, and ARK-15), and a water-cut remaining constant at a historical average of about 20%.[16]

24. The Respondents, however, indicate in some detail various alleged anomalies or errors in the Claimant's assumptions and in some of the data it used in its calculations. For example, the Respondents assert that, given the actual system's voltage and horsepower limitations, the Rakhsh Shuaiba submersible pumps could only produce 5100 barrels of fluid per day if the flowing bottom hole pressure were about 1060 psi. Furthermore, contrary to the Claimant's assumption, the Shuaiba wells, all of which (including the two new ones assumed by the Claimant) were under artificial lift by submersible pumps, could not feasibly be produced at a bottom hole flowing pressure of 100 psi. Normal IMINOCO practice, according to the Respondents, had been to produce at a pressure greater than 500 psi. The Respondents further criticize the Claimant's assumption that two new producing wells would be put on stream by 1982, a development completely unforeseen in IMINOCO plans.[17]

25. Core Lab attacks the Respondents' data and assumptions as unrealistic or misleading -- particularly their projections of water-cut and well productivities and their use of unnecessarily low pump capacities. With regard to the

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[16]Core Lab also used pump calculation forecasting and assumed as well the addition of two producing wells by January 1982. Core Lab, however, found it "unlikely that water-cuts will remain constant" and, therefore, projected an increase in water-cut, thus projecting greater decline rates after 1981 than did the Claimant.

[17]ECL, the experts retained by the Respondents, confirm much of the Respondents' technical assertions and indicate, in addition, that both the Claimant and the Respondents have used an excessive oil in place value. ECL itself arrived at its forecast by employing a material balance method in which it selected reservoir pressures "similar" to those used by AGIP in June 1978.

voltage and horsepower limitations, for example, Core Lab asserts that these could be overcome by adding transformers, using surplus generators available on the platform, and installing tandem or triple pumps. Core Lab also believes that the Respondents' contentions concerning the necessity of a 500 psi minimum bottom hole flowing pressure are unnecessarily high and that the Claimant's and Core Lab's assumption of 100 psi would have been adequate. Core Lab notes that the minimum bottom hole flowing pressure becomes important only after reservoir pressures decline to a certain point, a point that would be reached in Core Lab's calculations in the first quarter of 1983. In order to investigate the sensitivity of this parameter, Core Lab recalculated the forecast using 250 psi pressure, instead of 100 psi. The result was a 17% reduction in its projected primary recovery, from 33,288,000 to 27,508,000 barrels. Core Lab conceded that, if tandem or triple pumps were required, then the limiting flowing pressure could possibly be increased to 250 psi. Finally, Core Lab notes that, according to the Respondents' calculations, the reservoir would not be depleted in 1999, at the termination the the JSA. A prudent operator, however, would add two new wells in connection with the secondary recovery which would also aid in increasing primary recovery. These wells were required to deplete prudently the reserves "within the terms of the JSA."

26. The Claimant's assertions about future primary production possibilities from this field are not persuasive. The Claimant has not fully or convincingly dealt with several of the anomalies in its data as pointed out by the Respondents. Furthermore, the Claimant made no rebuttal at the Hearing to any of ECL's contentions with respect to this reservoir, including, for example, the assertions that the Claimant used an excessive oil in place value, that the Claimant used incorrect reservoir pressures, and that the Claimant's flowing bottom hole pressure would have an adverse effect on

pump life, efficiency, and cooling requirements. In this connection, at the Hearing ECL elaborated the possible difficulties in changing the voltage and horsepower capability of the facilities in order to achieve 100 psi minimum bottom hole flowing pressure. Moreover, the Claimant's (and Core Lab's) assumptions with regard to the addition of two new wells by the end of 1981 in conjunction with secondary recovery is not clearly justified, as will be pointed out in the following subsection on secondary recovery. In addition, the Claimant's expert, disagreeing with the Claimant's use of a constant water-cut, forecasted 20% less primary recovery. When considering the effect of increasing the bottom hole flowing pressure to 250 psi, Core Lab's forecast was 45% less than the Claimant's.

27. Finally, it is significant that various projections available in 1979 are more supportive of the Respondents' forecast than that of the Claimant. In 1974, for example, a report by AGIP on the reservoir forecasted that a total of between 39.6 million and 45.6 million cumulative [i.e., from 1971] barrels of oil could be recovered from the reservoir through primary recovery.[18] In 1979, therefore, after 23,692,000 barrels had been recovered since 1971, one could have expected, at least on the basis of that report, that between about 16 million and 22 million more barrels could be obtained from Rakhsh Shuaiba through primary recovery. In 1975, the Second Party Report forecasted that a total of about 44.7 million barrels would be produced between 1971 and 1984. Again, in 1979 on the basis of that report, the expectation would therefore have been for an additional 21 million barrels or so from primary production. The Geho Report of 1976 forecasted total recoverable primary reserves

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[18] A January 1979 report summarized the 1974 AGIP report, indicating that AGIP had estimated that total primary production would be about 40 million barrels.

at about 43.8 million barrels, thereby leaving, from the viewpoint of the 1979 analyst, about 20.1 million barrels yet to recover. Finally, a new 1978 AGIP report on the status of the field forecasted approximately 20.3 million barrels of oil remaining through primary recovery after 1978.

28. Based on this evidence, it would appear reasonable to conclude that, in September 1979, a buyer of the Claimant's JSA interests would have estimated that approximately 18,000,000 to 20,000,000 barrels of oil were recoverable from this reservoir during the remaining JSA period through primary recovery.

(b) Secondary Recovery

29. The Claimant bases its predictions for secondary recovery in Rakhsh Shuaiba on alleged IMINOCO plans for such recovery. Water injection would proceed, it asserts, starting in July 1981, with the injection of 20 thousand barrels of water per day ("BWPD") through two wells (RK-8 and RK-17) drilled for the Rakhsh Arab C water injection project and dually completed for production in Shuaiba. The Claimant assumed that production would come from the three existing producing wells (ARK-13, ARK-14, and ARK-15), and two additional ones to be added by the end of 1981. The Claimant asserts that it derived its forecast through "frontal advance" calculations which began with the adoption of the average relative permeability relationships reported in the 1974 AGIP model study. Core Lab forecasted about 5% more secondary recovery than the Claimant, a result of adjusting the Claimant's projection to reflect Core Lab's more favorable interpretation of well productivity indices and a less favorable viewpoint on areal sweep efficiency.

30. The Respondents reject the Claimant's assertions on secondary recovery for most of the same reasons as they did

for Rakhsh Arab C. In support of their assertions with regard to Rakhsh Shuaiba, the Respondents point out that, after 1974 when the Development Committee accepted an AGIP study on water injection, no further action was taken except -- as the Claimant has pointed out -- for the placement of the project on the agenda of a Development Committee meeting scheduled for January 1979, but never held. Thus the water injection scheme had been neither planned, proposed nor even studied. Therefore, the Respondents assert that the earliest possible date for secondary recovery would have been January 1992.

31. The Respondents also have numerous technical objections to the Claimant's contentions. They state that well RK-17 was completed in 1979 as a single injector in the Rakhsh Arab C reservoir and could not be used as a water injector in Shuaiba. The Respondents add that the Claimant's assumption of an injection rate of 20,000 BWPD was too high, had neither been studied nor ever intended, and could be harmful for the reservoir. In this connection, the Respondents note that the 1974 AGIP Report indicated that 8,000 BWPD was the optimum rate through well RK-8, provided that two additional wells were drilled.[19] An injection rate of 15,000 BWPD was rejected because of the danger of fracturing and consequent reduced recovery. The Respondents point out that even the plan to inject RK-8 at the rate of 8,000 BWPD had not been approved and faced technical questions as to the compatibility of the injected seawater with the Shuaiba formation rock and water and the possible problems of using the same well to inject both the Arab C and the Shuaiba reservoirs.

32. The Respondents also allege other technical problems having to do with the data used by the Claimant to calculate

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[19]Two additional wells, ARK-14 and ARK-15, were drilled in 1975.

sweep efficiency and relative permeability, the formula used by the Claimant for the calculation of produced injection water, and the Claimant's concept of effective sweep efficiency. The Respondents' projections are based on injection into well RK-8 at 8,000 BWPD and no additional producing wells.

33. The Claimant's contentions regarding the timing and scale of secondary recovery are not persuasive, and moreover the Claimant has not effectively rebutted the Respondents' technical objections. More importantly, from the standpoint of September 1979, and in marked contrast to the case for Rakhsh Arab C, the evidence indicates that a reasonable investor would have been in considerable doubt as to when secondary recovery would occur in Rakhsh Shuaiba. In any case, little evidence exists that such an investor would have had reason to believe that secondary recovery by 1999 would be of the order of magnitude posited by the Claimant or Core Lab. Although the Claimant repeatedly asserts that secondary recovery in Rakhsh Shuaiba was "in the planning stages", the evidence suggests that such planning was in fact, at best, in its very early stages.

34. Secondary recovery from Rakhsh Shuaiba was discussed early in the development of the reservoir. The commerciality report of 1969 for the Rakhsh Field, for example, contained mention of early secondary recovery from the Shuaiba reservoir. In 1972 the Development Committee apparently worked on model studies of Rakhsh Shuaiba and Arab C, focusing first on Shuaiba. By mid-1972, however, the Development Committee declared Arab C to have the highest priority as the most important reservoir. In 1973, after obtaining preliminary AGIP model results, the Reservoir Model Subcommittee recommended water injection in Shuaiba through well RK-8 in conjunction with the secondary recovery project in Arab C. The Development Committee requested two further model runs, one with two additional

production wells and injection of 8,000 BWPD, and the other at 15,000 BWPD.

35. In March 1974 the AGIP study on these model runs was issued. It rejected injection at 15,000 BWPD, recommended injection as soon as possible into well RK-8 at 8,000 BWPD, and forecasted secondary incremental recovery of about 25 million barrels over a 15-year time span, if two additional producing wells were added. In May 1974 the Development Committee recommended that the Rakhsh water injection plant capacity should provide 65,000 BWPD for Arab C and 20,000 BWPD for Shuaiba. The Committee also recommended the two additional production wells and called for injectivity tests in well RK-8. The Committee accepted AGIP's report of March but recommended that IMINOCO "delay action on the conclusions" due to the fact that "the amount which could be injected in well RK-8 is insufficient for a very efficient water flooding." Further studies would therefore be needed. In October 1974 the Committee recommended that IMINOCO commission a vertical cross-section model, followed by a three-dimensional model.

36. In 1975, the two new wells, ARK-14 and ARK-15 were completed. Early in 1975, however, the Development Committee decided to postpone any further study on water injection until the following additional information was collected: core analysis, additional pressure measurements, and geological information from the drilling of two water injection wells to Arab C. After 1975, the first mention in evidence of secondary recovery from Shuaiba apparently occurred at a meeting at AGIP's offices in May 1978. AGIP confirmed its previous 1974 report. Water injection into well RK-8 was again recommended as the most feasible project but "other possibilities could also be studied, so that this waterflood could be carried out concurrently with Arab C project".

37. An AGIP report of June 1978 recommended further pressure surveys and reaffirmed that water injection should take place concurrently with Arab C at an optimum rate of between 7-8 thousand BWPD. Were such a project to begin in 1981, a total cumulative recovery of about 72 million barrels by the year 2008 could be achieved, a secondary increment therefore of about 28 million barrels. In October 1978, NIOC commented that water injection would proceed in six Arab C wells; 10,000 BWPD would "later" be injected into Shuaiba producing a 15 million barrel secondary increment by the end of 1999.

38. Secondary recovery in Rakhsh Shuaiba was on the agenda of a Development Committee meeting scheduled, but not held, on 18-19 January 1979. The Claimant apparently prepared some background information for that meeting. The Claimant noted in a letter to AGIP in January 1979 that no detailed study had apparently been made since the 1974 AGIP study and that the Claimant planned to request an updated evaluation of the project. The Claimant observed that sufficient capacity had been included in the Arab C waterflood project to inject 8,000 to 10,000 BWPD into Rakhsh Shuaiba. That and the availability of well RK-8 provided the possibility of a "limited rate waterflood . . . at little additional cost."

39. While the above history reveals that by 1979 occasional consideration had been given to secondary recovery from Rakhsh Shuaiba, few if any concrete steps had been taken towards actual planning or implementation and certainly nothing on the scale suggested by the Claimant. Indeed, evidence exists that in 1975, 1978, and 1979, further studies were needed and called for and would have been requested by the Claimant in 1979. Furthermore, an examination of the specific guidelines to the five-year plans, the plans themselves presented in 1977 and 1978, the meetings to discuss the plans, and other records reveal no trace of any mention of Rakhsh Shuaiba secondary recovery planning,

implementation, budgeting, or expenditure authorization, not even under the sections in the five-year plans entitled "Projects under Study."

40. Given all the evidence, a conclusion that a secondary recovery project would proceed in 1981 or at any early date in Rakhsh Shuaiba would be highly speculative and would not have been reasonably held in 1979.

41. Contemporary projections, including the 1974 AGIP report, the June 1978 AGIP report, and the October 1978 NIOC comments, indicate that secondary recovery in the Shuaiba reservoir could be expected to produce between 15 to 28 million barrels (over various periods of time). Nevertheless, it seems doubtful that the necessary plans had been made or were in prospect by mid-1979 to justify the conclusion that such quantities, which might ultimately be recoverable through a secondary recovery program, were so recoverable during the life of the JSA. It seems more likely that secondary recovery could not have begun earlier than about 1985 and 1986 and more prudently would have been assumed to begin only in the late 1980's. On that basis, it would appear reasonable to have estimated that approximately 5,000,000 to 10,000,000 barrels of oil would be recoverable as a result during the life of the JSA.[20]

42. In conclusion, on the basis of the above analysis, the total oil recoverable through both primary and secondary methods from Rakhsh Shuaiba would reasonably have been estimated in 1979 in a range between 23,000,000 and 30,000,000 barrels.

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[20]The question of the impact on the value of the Claimant's interests in the JSA of the risk that the Revolution could have resulted in NIOC's seeking some further delay in this secondary recovery project -- for
(Footnote Continued)

(3) Rakhsh Mishrif

43. The Claimant forecasts recovery of 3,804,000 barrels of oil from this reservoir between 1979 and 1999. The Respondents deny that any further oil would be recovered from the reservoir. Core Lab forecasts recovery of 4,072,000 barrels, and ECL, while questioning whether any oil would be recovered, considers 1,319,000 barrels recoverable during that period.

44. Only one well, Ark-4, was completed for Rakhsh Mishrif production, and it was shut-in during November 1978 due to low well-head pressure. The Claimant asserts that it would have been feasible to install pumps capable of lifting oil from that well and that it would be unreasonable not to do so. The Claimant also asserts that another well, Ark-7, which had been producing from the Arab C reservoir and was shut-in in mid-1978, could be successfully converted to produce oil from the Mishrif reservoir and that such conversion should be foreseen for 1980. The Respondents point out that no plans existed in IMINOCO in 1979 to bring either well into production, and they argue that if Ark-4 were equipped with pumps, the actual production would be less than the Claimant forecasts because of decreasing well-head pressure. The Respondents also point out that neither the Second Party Report of 1975 nor the Geho Report forecast any production from the Rakhsh Mishrif reservoir after 1978.

45. It is undisputed that further production from well Ark-4 by natural flow was impossible, but it seems equally clear that the installation of pumps would have permitted recovery of at least an additional 1,319,000 barrels. It

(Footnote Continued)
example, to 1992 -- should be dealt with separately in the Award since this analysis discusses only the amount of oil technically recoverable.

should be noted that, as of 1979, 21 wells in the Rakhsh and Rostam Fields were equipped with pumps to lift oil artificially. The Respondents and ECL do not take issue with the assertions of the Claimant and Core Lab that technically it was possible to convert well Ark-7 to Mishrif production, and therefore concluding that such conversion would have been feasible seems justified. The Respondents and ECL also do not take issue with the assertions by the Claimant and Core Lab that conversion of Ark-7 would be likely to permit production of approximately the same quantity of oil as could be produced from Ark-4 if it were equipped with pumps, and therefore that conclusion would also be reasonably accepted.

46. With respect to the total quantity of recoverable oil from the Ark-4 well, it seems more reasonable to accept the more conservative forecast of ECL that approximately 1,300,000 barrels could be recovered. A similar quantity could be recovered from the converted well Ark-7. Consequently, the total recoverable oil from Rakhsh Mishrif would reasonably have been estimated in 1979 as approximately 2,600,000 barrels.

47. In conclusion, based on the evidence presented the total oil recoverable through both primary and secondary methods from the Rakhsh Field would reasonably have been estimated by a buyer in 1979 within a range of between 153,600,000 and 162,600,000 barrels.

b) The Rostam Field

48. The Rostam Field had four producing reservoirs, the Shuaiba, the Mishrif, the Arab A-1, and the Arab C. Of these, the most prolific producer was the Shuaiba.

(1) Rostam Shuaiba

49. The Claimant asserts a total recovery of 137,669,000 barrels of oil from the Rostam Shuaiba Reservoir between 1979 and 1999, of which 50,696,000 barrels would be from primary recovery and 86,973,000 barrels from secondary recovery.[21] The Respondents counter with a projection of a total recovery of 57,884,000, of which 36,401,000 would be from primary recovery and 21,483,000 from secondary recovery.[22]

(a) Primary Recovery

50. Both the Claimant and the Respondents base their primary recovery projections on a 1974 model study prepared by the Claimant at the request of IMINOCO and entitled "Case D". That study predicted oil recovery from March 1974 through February 1989 from existing wells. The Claimant makes three adjustments to the model. First, it reduced the predicted recovery by 8 percent annually to reflect actual results achieved from 1974 through 1978. Second, it extrapolated the forecast from February 1989 through August 1999 by using a decline rate of 5.04 percent annually, which was the average decline rate predicted in Case D for the years 1974 through 1989. Third, it changed the predicted primary recovery from 1984 through 1999 by increasing it for ten years by small and varying percentages and then reducing it in subsequent years as a result of its forecast that seven new wells would be drilled by 1984 as part of a water-injection, secondary recovery project.[23] Core Lab

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[21]Corresponding figures for Core Lab are a total of 132,639,000 barrels, of which 60,339,000 would be from primary and 72,300,000 from secondary recovery.

[22]Corresponding figures for ECL are a total of 58,258,000 barrels, of which 37,938,000 would be from primary and 20,320,000 from secondary recovery.

[23]The effects of the seven wells on primary production (Footnote Continued)

differs from the Claimant by refusing to make the 8 percent annual reduction in the Case D forecasts, which it believes unjustified, and, less significantly, in its calculations of additional primary recovery resulting from the seven additional secondary recovery wells.

51. The Respondents agree with the Claimant's 8 percent annual reduction. In extrapolating the forecast of Case D from 1989 to 1999, however, they use a far greater decline rate than the Claimant -- 22.8 percent, rather than 5.04 percent -- which they draw from the Second Party Report of 1975. With respect to the additional primary recovery resulting from the drilling of seven wells for purposes of secondary recovery, they agree that such wells would result in some additional primary recovery for a number of years, but they assert that the secondary recovery project could not be in place until 1 January 1992, and they calculate such additional recovery from 1992 through 1999 at a total of 1,295,000 barrels.

52. ECL takes a different approach, formulating its own decline curve over the entire period from 1979 through 1999 without reference to Case D or the 1975 Second Party Report. ECL states that it has arrived at its production forecast by first determining the decline rate of historical oil production potential from 1971 through December 1978. Historical production potential, it says, declined consistently over these years, reaching 10.66 percent by 1979. ECL believes a consistent yearly decline rate in production would have continued -- from around 10.66 percent in 1979 to about 7 percent in 1983, 5 percent in 1989, and about 3 percent in 1999. Next, it determines how much of the oil production potential was actually produced by the reservoir for the

(Footnote Continued)
had been foreseen in another study the Claimant prepared for IMINOCO, entitled "Case B2-A".

years 1971 through 1978. It claims that, on average, 86.8 percent of the oil production potential was actually produced during those years. Thus, it reduces the yearly oil production potential by 13.2 percent to arrive at its final yearly production forecast. ECL, consistent with its guidance from the Respondents, does not envision any new drilling.

53. Thus, the two principal differences between the Parties that the Tribunal must resolve are the appropriate decline rate between 1989 and 1999 and the date for the entry into service of the seven secondary recovery wells. A difference with far less significant consequences also exists with respect to the calculation of the quantity of additional primary recovery that would result from the additional secondary recovery wells.

54. With regard to the appropriate decline rate, the Respondents have offered no plausible explanation why the decline rate should increase so dramatically after 1989, and such a sharp change is rejected by the Claimant, Core Lab, and ECL. If, as the Claimant and the Respondents agree, Case D is (after the agreed 8 percent reduction) a reliable forecast to early 1989, then the decline trend established through those years would more reasonably be extrapolated forward than a new, and much steeper, rate.

55. The 1975 Second Party Report, upon which the Respondents now rely, does not explain or justify the steep decline rate it predicts for the period from 1989 through 1999. The Claimant points out that it was prepared with a view to the Second Party's negotiations with NIOC of revised fiscal arrangements in the JSA. Moreover, its pessimistic conclusions are not supported by other, roughly contemporaneous studies. While these other studies, the 1976 Geho Report, an independent 1974 simulation study prepared for NIOC, and the 1974 Case D itself, do not all deal with

annual decline rates or cover the same periods of time, their forecasts of total primary recovery from the Shuaiba reservoir are closer to the predictions of the Claimant than to those of the Respondents. The Claimant predicts total primary recovery without additional drilling for secondary recovery of about 114,600,000 barrels by 1999. The Respondents predict total primary recovery of about 103,770,000 barrels by the same date. The Geho Report predicted total recovery of 113,465,000 by 1994. The 1974 simulation study predicted a total recovery of 105,000,000 barrels by 1991, and Case D predicted a total recovery of 101,400,000 barrels by early 1989. It should be noted that primary recovery through 1978 from this reservoir totaled some 68,600,000 barrels.

56. Thus, quite apart from the question of additional recovery that might result from additional wells drilled for purposes of secondary recovery, it appears reasonable to conclude that a buyer in 1979 would have estimated that approximately 43,000,000 barrels of oil seemed to be recoverable from this reservoir during the remaining JSA period through primary recovery.

57. With respect to the question of when the additional wells could reasonably have been expected to be completed, it should be noted that the Parties seem to agree in their pleadings that, if and when implemented, the scheme would envision seven additional wells and that those wells, quite apart from secondary recovery, would increase overall primary recovery to some extent, but the Parties remain eight years apart in their forecasts of when those additional wells could be expected to begin production.[24] The evidence reveals the following relevant history.

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[24]In their early pleadings the Respondents asserted
(Footnote Continued)

58. Several water injection schemes were considered by IMINOCO around 1974 and 1975. In October 1974, the IMINOCO Development Committee recommended that a predictive study be undertaken by the Claimant on the increased oil production which would likely result from several water injection schemes under consideration. This study, which was presented in December 1974, analyzed two alternative water injection projects (Case A and Case B). In early 1975, an IMINOCO subcommittee comprised of one member from each IMINOCO partner, expressed its preference for one of the two alternatives (Case B), but suggested that two additional variations of Case B should be studied before taking a decision on whether to proceed. The Claimant also undertook these additional studies (Case B1 and Case B2), which were presented to the subcommittee in January 1975. Sometime in early 1975, the subcommittee apparently expressed its preference for Case B2, which envisioned the drilling of seven injection wells and seven additional production wells, and which predicted a cumulative recovery from the reservoir by 1989 of 171,700,000 barrels of oil. However, the subcommittee also decided that an additional study should be conducted before taking a decision on implementing Case B2 which would indicate how much of the additional oil produced after its implementation would be due to primary depletion (due to the drilling of the seven additional producing wells). This study, called Case B2-A, which was completed in April 1975, indicated that, with the seven additional wells, primary depletion would increase significantly.[25]

(Footnote Continued)
that the Rostam Shuaiba secondary recovery project would not be implemented at all during the life of the JSA. In their rebuttal brief, however, they accept implementation of the project in 1992.

[25]The statistics showed that before the seven wells were drilled, the reservoir would produce 101.4 million barrels through primary recovery by 1989 (Case D findings), while after the drilling of the seven wells, primary
(Footnote Continued)

59. Implementation of the project was further delayed in 1975 and 1976, initially because certain water injectivity tests were carried out on well AR/28 to determine whether the rates of injection assumed in Case B2 were possible. That report, which reportedly confirmed that the formation could take water at the rates assumed in the model, was presented to the IMINOCO Development Committee in March 1976. In that same month, NIOC accepted the results of the test during a Development Committee meeting and recommended implementation of Case B2 without further delay, but AGIP stated that the large investments involved in implementing the B2 project should not be incurred without running a pilot project because, as the minutes of that meeting state, "limited experiences were gained during the injectivity test of well AR-28." Progress on designing and implementing the pilot appears to have been rather slow. In January 1978, the IMINOCO Development Committee chose Case B2 to be the "pattern of water injection for Rostam Shuaiba." It also agreed to carry out preliminary engineering studies so that an economic feasibility study of Case B2 could be drafted, and it suggested designing and implementing the pilot "without any further delay." By December 1978, both Parties had approved the pilot project and IMINOCO had approved a budget for carrying it out.

60. For purposes of establishing when the water injection project could reasonably have been expected in 1979 to be implemented, given this chronology, it appears that the following activities would still have been required: (1) approval of an economic feasibility study to estimate the cost of the project; (2) assembly of the equipment needed to implement the pilot and to undertake the test; (3)

(Footnote Continued)
recovery would be 110.5 million barrels and secondary recovery would be 61.2 million barrels.

completion of the engineering studies on the full-scale project; and (4) implementation of the full-scale project itself.

61. In December 1977, the IMINOCO Board of Directors instructed the company to prepare an economic feasibility study to estimate the cost of implementing Case B2. The evidence is clear that such a study had to be made both so that the board could consider the project budget and as a basis on which the detailed engineering plans could be prepared. Pursuant to this instruction, a draft of the economic feasibility study was completed in June 1978. It estimated the cost of undertaking Case B2 under six scenarios, the variables involving whether to build new platforms, what type of generator to use, and so forth. One of the six scenarios, the estimated cost of which was U.S.$47,500,000, was chosen in June -- the Claimant says "IMINOCO" chose it, while the Respondents claim it was merely accepted by IMINOCO's engineering section, not by the Board of Directors. Minutes of an IMINOCO Board of Director's meeting held in June 1978 suggest that the Respondents are correct. Those minutes mention that several alternatives concerning whether to use existing platforms or to build new ones for implementing the Rostam water injection project were still being considered. As the feasibility study would presumably have had to estimate the cost of the engineering scheme finally proposed for the project, the Respondent's claim that, by June the Board of Directors had not yet approved a final feasibility study seems credible.

62. While a final version of the feasibility study may not have been completed, there is no indication that doing so would have taken a long time once an engineering alternative

was chosen,[26] or that not having completed the study would have delayed starting the pilot test, which was the most immediate step which had to be taken. The Board of Directors mentioned in the June 1978 meeting that the pilot test and the detailed engineering work could start upon completion of the preliminary engineering tests and the economic feasibility study. Since the pilot project was later approved and budgeted in December 1978, it seems reasonable to assume either that the feasibility study was also considered approved by that time or that the Board wanted the pilot project to proceed without further approval.

63. The time required to implement the pilot project had been estimated at two years in several documents prepared by the Parties in commenting on the proposed Five Year Plan. Neither of the Parties has questioned or otherwise contested this estimate, and, although the Five Year Plan was not officially approved, there does not appear to be any reason to doubt the accuracy of the two-year estimate it made for carrying out the pilot project.

64. Although the Second Party had insisted on deferring a decision on whether to proceed with the full-scale project until after the results of the pilot test were known, it did agree, through the IMINOCO Development Committee, to allow the engineering work for the full-scale project, which the IMINOCO Development Committee had indicated in November 1976 was a sixteen-month project, to proceed along with the implementation of the pilot project. The Board of Directors approved this arrangement as well. Moreover, the tentative Rostam water injection schedule attached to the proposed Five Year Plan also provided that the full-scale engineering

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[26]The draft feasibility study completed in June 1978 had been requested by the Board only in December 1977, and much of that study could probably have been incorporated into the final version.

project should proceed simultaneously with the pilot project. Accordingly, it appears reasonable to conclude that, had the Parties wished it, preparation of the engineering project would not have delayed the implementation of the full-scale project.

65. However, as mentioned above, it is not entirely clear that IMINOCO had determined exactly which engineering alternative it preferred or had given final approval to a feasibility study estimating its cost. (Clearly, it could not begin the detailed engineering work until it had chosen one of the alternatives.) The June 1978 Board of Directors meeting shows that an engineering alternative had not been finally selected by that time. However, the 1979-1983 Five Year Plan earmarks U.S.$700,000 for engineering work on the project, which indicates a choice may have later been made or, at least that one was under consideration. Even if such a choice had been made, it should be noted that the Board of IMINOCO does not appear to have approved the expenditure of funds for it. For example, the preliminary IMINOCO Five Year Plan 1979-1983, which was never officially approved, mentions that the total cost of the Rostam engineering project was U.S.$700,000, and it states that U.S.$400,000 were to be spent in 1979 and U.S.$300,000 in 1980. This is the same time period in which the Five Year Plan envisioned the implementation of the pilot project. It adds in a footnote, moreover, that IMINOCO had requested U.S.$250,000 for the project in 1978 and that amount was approved as "firm" by the First Party, but "contingent" by the Second Party. Therefore, it is clear that no funds had been spent for engineering work on the project up to the time the Five Year Plan had been drafted. An IMINOCO letter to NIOC dated 11 April 1979 regarding the 1358 (1979) budget includes a U.S.$400,000 entry for the engineering project which, it states, had been "carried forward" from the budget for 1978 and the first three months of 1979. While the letter shows that IMINOCO may have wanted to obtain approval to begin the

project, it also confirms that no funds had yet been spent on it. The Claimant has not provided other evidence that would lead to a different conclusion. Thus, while the evidence confirms that the engineering project could have proceeded apace with the pilot project, and that the Second Party agreed in principle that it should, at least by April 1979, the necessary steps had not yet been taken to ensure that it would.

66. The time needed to implement the water injection project itself is the most crucial aspect of this analysis, yet curiously the least commented upon by the Parties. The following points appear to be established. First, at least one of the Second Party members had clearly insisted that the results of the pilot project be known before it would agree to authorize IMINOCO to proceed with the full-scale project. Second, the Parties had agreed that the detailed engineering studies, which had to be finished before undertaking the full-scale project, and which appear to have required about sixteen months to complete, could be undertaken concurrently with the pilot; however, the funds for the engineering had not been budgeted by mid-1979, and it is unclear whether IMINOCO had finally settled on an engineering alternative on which the detailed engineering work could be based. Thus, there can be no clear answer to the question whether engineering work would in fact have delayed implementation of the project, but it clearly need not have done so if the Parties were prepared to make the necessary decisions. Thus, assuming a desire to proceed, it appears reasonable to conclude that the water injection project could have been fully implemented sometime in 1984.

67. Neither the Respondents nor ECL have contested the technical feasibility of beginning full-scale secondary recovery by 1 January 1984. The Respondents argue that the economic changes in the country, the lack of skilled manpower after the revolution, the lack of normal working

conditions, and the lack of NIOC funds made execution of such projects after 1978 altogether impractical. However, they in no way assert that beginning the project in January 1984 was technically unrealistic.

68. The proposed 1979-1983 Five Year Plan, which scheduled the pilot test and the engineering work to begin in early 1979, with the full-scale project to follow their completion, envisions completion of the project by the time forecasted by the Claimant. NIOC's comments on the Plan made in October 1978 also predict that the Rostam water injection project could have had a noticeable effect on Rostam production by the end of 1362 (i.e, around the end of 1983) assuming implementation of the pilot in 1979. While these predictions do not, of course, mean that the waterflood would have started by that date, they do indicate a belief among the Parties that such a date was thought of as feasible. The water injection studies (Cases B1 and B2) both assume a lag-time of about two to three years for completing the water injection projects.

69. In view of this evidence, it appears reasonable to assume that the implementation of the secondary recovery project by 1984 would have been technically feasible if the necessary decisions were taken in 1979 and that a reasonable investor in 1979 would have so understood the situation. Therefore, in calculating the quantity of oil recoverable from the Rostam Shuaiba reservoir, such an investor would have added the additional amounts recoverable because of the seven additional wells that would be drilled for purposes of secondary recovery.[27]

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[27] The question of the impact on the value of the Claimant's interests in the JSA of the risk that could have been perceived in September 1979 -- that the necessary decisions would not be taken in 1979, or at any early date,
(Footnote Continued)

70. With regard to the question of the quantity of this additional primary recovery, the Claimant asserts that it would total 4,751,000 barrels. The Respondents (assuming implementation only in 1992) assert that it would total 1,295,000 barrels. It should be noted that the 1975 Case Study B2-A predicted 9,100,000 additional barrels of primary recovery between 1977 and 1989. That study provides the technical foundation for the formula used by the Claimant in its present calculations.[28] The Respondents have presented no evidence to discredit the formula or the Claimant's percent estimate. Moreover, the Respondents' alternative calculation is based on a simple mathematical formula,[29] for which they provide no supportive evidence. Thus, it appears more reasonable to conclude that an additional quantity closer to 4,000,000 barrels of oil would have been estimated as recoverable through primary recovery as a result of the implementation by 1984 of the water injection, secondary recovery project. Thus, on that basis, in total, it would have been reasonable for a buyer in 1979 to estimate that approximately 47,000,000 barrels of oil were recoverable from this reservoir during the remaining JSA period through primary recovery.

(Footnote Continued)
to begin the secondary recovery project -- are dealt with separately in the Award, since this analysis discuses only the amount of oil technically recoverable.

[28]Case B2-A concluded that the seven additional producing wells would increase primary production by 1.56 percent in the first year, 1.44 percent in the second, 1.36 percent in the third and so forth at consistently declining percentages for ten years. Thereafter, primary recovery would decrease slightly from the primary recovery expected had the additional wells not been drilled. Case B2-A also made clear that the earlier the additional wells were drilled, the greater the additional primary recovery would be.

[29]Total annual forecasted primary production from the reservoir is divided by the number of wells (16) to arrive at an average well production. That average is then
(Footnote Continued)

(b) Secondary Recovery

71. As noted above, the Parties' forecasts of secondary recovery from this reservoir differ greatly, with the Claimant predicting 86,973,000 barrels and the Respondents predicting 21,483,000 barrels.[30] To a great extent this difference reflects the Parties' difference of eight years as to the date by which the secondary recovery project could be expected to be implemented, and, as has already been concluded, the Claimant is correct to assert that the project could have been implemented by 1984 if the necessary decisions had been taken in 1979.[31] However, not all of the difference in estimates of secondary recovery is attributable to the starting date. There are also significant disagreements about the feasible rate of water injection and the methodology to be used in calculating secondary recovery.

72. With respect to the rate of water injection, the Claimant makes no adjustment to the relevant inputs to its Cases B2 and B2-A. The Respondents and ECL assert, however, that an injectivity test carried out on well AR/28 indicated that pressure on the injection wells would have to be only about 3,000 pounds per square inch, that is approximately 20 percent lower than assumed in Case B2, in order to avoid harmful fracturing of the reservoir rock. It will be recalled that, in 1976, the IMINOCO Development Committee accepted the results of the AR/28 injection test as showing

(Footnote Continued)
multiplied by 23, which is the number of wells (16), plus the seven new wells.

[30]The corresponding figures for Core Lab and ECL are 72,300,000 barrels and 20,320,000 barrels respectively.

[31]As noted above, the obvious risk that the project would not be implemented as soon as feasible is considered separately in the Award.

that the formation could take water at the rates foreseen in the model. In their rebuttal pleadings, however, the Respondents assert that the test, in fact, showed that both pressure and quantity of water would have to be reduced by approximately 20 percent, and they provide a copy of the March 1976 IMINOCO Report on the test. The Claimants had no opportunity to respond to this argument and evidence until the Hearing, at which the representative of Core Lab acknowledged that the test showed fracturing. He pointed out, however, that the well in question had previously been fractured and therefore could have been expected more easily to fracture once again, and he noted that there was no evidence that such a pressure reduction would be required elsewhere in the reservoir.

73. ECL also asserts that a 20 percent reduction in pressure and the rate of injection would result in slightly more than a 20 percent reduction in secondary recovery. Core Lab argues that fracturing by water injection would not necessarily reduce recovery. In view of this uncertainty, which only the contemplated pilot test could have resolved, and in exercising the prudence which a buyer in September 1979 would have, it appears more reasonable to reduce the Claimant's estimates of secondary production from this reservoir by approximately 20 percent.

74. With respect to the proper methodology for calculating secondary recovery, the Claimant has based its estimates on the 1975 Case B2 and Case B2-A studies it had done for IMINOCO, modifying them to account for the seven-year delay in the expected implementation of the project and to account for the differences in the predicted and actual production from 1974 through 1979. The Claimant modified the case study for reservoir voidage and changes in the gas to oil ratio (GOR), the water to oil ratio (WOR), and the pressures in the reservoir. As a result of the changes, the Claimant calculated that the peak production rate during the

waterflood would be lower than predicted in Case B2 and would occur 12 to 14 months later than predicted in Case B2, and that the decline rate would be similar to that predicted by Case B2.

75. The Respondents also start with Cases B2 and B2-A, but their modifications are made on different bases (and, of course, start with 1992, not 1984). They determine the percentage of remaining reserves estimated by the cases to be recoverable yearly as a result of water injection and then multiply those percentages by their calculations of remaining reserves for each year of the project. ECL criticizes the Respondents' methods as "arbitrary" and as not reflecting the physical processes taking place in the reservoir. ECL comments that, due to a GOR limit imposed by NIOC in 1976/1977, reservoir pressure decline had been virtually halted, and, accordingly, "production response to water injection, in terms of cumulative incremental oil production as a function of the cumulative volume of water injected, will be similar" to the results of Case B2. ECL, accepting the Respondents' 1992 starting date, concludes that lesser secondary production would result from the lesser volume of "target oil" and the 20 percent lower rate of injection.

76. Finally, comparison of the Parties' forecasts with the contemporaneous model studies clearly favors the prediction presented by the Claimant. These model studies, Cases A, B, B1 and B2, calculated cumulative recovery from 1977 to 1989, assuming various water injection patterns and rates. Case A showed an incremental increase of 81.5 million barrels of oil up to 1989; Case B showed an incremental increase of 55.7 million barrels of oil up to 1989; Case B1 showed an incremental increase of 58.7 million barrels of oil up to 1989; and Case B2 showed an incremental increase of 70.3 million barrels up to 1989. Moreover, both Parties, as well as ECL and Core Lab, accept the basic underlying assumptions

of Case B2 (except for the water injection rate), and would adjust its findings to account for such factors as the delay in implementation of the project and reservoir voidage.

77. Accordingly, it appears reasonable to find that a buyer in 1979 would have estimated that approximately 65,000,000 to 70,000,000 barrels of oil would be recoverable from this reservoir during the life of the JSA by means of secondary recovery.

78. In conclusion, it appears reasonable to conclude that the total oil recoverable through both primary and secondary recovery from the Rostam Shuaiba reservoir would reasonably have been estimated by a buyer in 1979 at approximately 115,000,000 to 120,000,000 barrels.

(2) Rostam Mishrif

79. The Claimant asserts a total recovery of 16,554,000 barrels of oil from the Rostam Mishrif reservoir between 1979 and 1999, all of which would be from primary recovery. The Respondents counter with a projection of a total recovery of 11,957,000 barrels, all of which would be from primary recovery.[32]

80. The Parties agree that all production from this reservoir would come from the five wells in production in 1979, that those wells would continue to produce by pump throughout the remaining life of the JSA, and that the production history of the reservoir during the years 1975-1978 provides the best basis for predicting production from 1979 to 1999 because it appears that, prior to 1975, recovery of oil from the reservoir was commingled with oil from the Shuaiba

[32] Corresponding figures for Core Lab are 25,257,000 barrels and for ECL 11,277,000 barrels.

reservoir. Nevertheless, differences in assumptions and methods of calculation have resulted in the significant differences in their estimates that are noted above. Perhaps the most important single difference relates to the oil production potential of the five wells at the end of 1978. The Claimant asserts that it was 6,460 barrels of oil per day, and the Respondents counter with the assertion that it was 5,080 barrels of oil per day. However, the Parties have not supported their assertions with adequate evidence to permit definitive confirmation of either assertion. There is evidence that 2,026,000 barrels were produced from the reservoir in 1977 and 1,565,000 barrels in the strike-shortened year 1978, and the Claimant has not taken issue with the Respondent's assertion that the efficiency of the five wells producing from the reservoir was about 88 percent. These figures would seem to support a production potential closer to that claimed by the Respondents than that claimed by the Claimant. On the other hand, the only 1979 production report in evidence -- that for the month of September, shows the production capacity of the five wells at that time as 5,559 barrels of oil per day.

81. Other significant differences relate to the Parties' calculations of decline rates for the reservoir (the Claimant's rates vary from 7 to 10 percent, and the Respondents' rate is 11 percent) and the methods used to apply the selected decline rate. Other aspects of both Parties' analyses seem questionable, in particular the application by the Respondents of an average decline rate derived from four wells to the new fifth well which began production in 1977 and the use by the Claimant of a reservoir-wide decline curve that forecasts 2,248,000 more barrels of oil production in the years from 1979 to 1999 than would result from the sum of its individual well forecasts.

82. The Second Party Report of September 1975 and the Geho Report of June 1976 forecast future production from Rostam

Mishrif. In aggregate terms, both reports forecast cumulative production from the reservoir at levels lower than the Claimant's estimate but higher than the Respondents' estimate. The Claimant's cumulative production estimate calls for 35,347,000 barrels of oil to be recovered by 1999, while the Respondents put the figure at 30,750,000. The Geho Report estimates total recoverable primary reserves at 32,498,000 barrels, and the Second Party Report predicts a recovery of 31,701,000 barrels of oil by 1988.

83. On balance, a finding that the total oil recoverable from the Rostam Mishrif reservoir during the life of the JSA would reasonably have been estimated in 1979 at approximately 13,000,000 barrels seems justified.

(3) Rostam Arab A-1

84. The Claimant forecasts recovery of 2,484,000 additional barrels of oil from this reservoir. The Respondents assert that the reservoir had been depleted and that no additional recovery was feasible.[33]

85. The Parties agree that the four wells that had produced oil from this reservoir (a cumulative total of approximately 11,344,000 barrels), were shut-in at various times during the years 1970 to 1975 because of high water-cut. The Parties also agree that further production from the reservoir was impossible by means of natural flow. The Claimant asserts, however, that further production would be possible from two of those four wells (AR-7 and one unidentified) if pumps were installed. Core Lab concurs, that additional oil was recoverable, and both the Claimant and Core Lab foresee

[33] Core Lab forecasts recovery of 1,293,000 barrels, and ECL foresees the possibility of recovery of 1,100,000 barrels from 1979 to 1995.

production continuing until the two wells would be converted to Shuaiba production in conjunction with the start-up of the water injection project for that reservoir, which, as discussed above, could have been foreseen in 1979 to have occurred by 1984. ECL stated that the installation of a pump would make possible further production by one well, AR-7, but it did not consider the possibility of installing a pump in a second well, as that "would have conflicted with IOOC guidelines."

86. The Respondents point out that IMINOCO never formulated any plans for or otherwise discussed the installation of pumps in any of these wells or even the general question of resumption of production from this reservoir, and they assert that such resumption would not have been feasible in light of the pump capacities and water processing facilities that would have been required. They also point out that the Geho Report in June 1976 declared the reservoir to be depleted and that the 1975 Second Party Report showed no predicted recovery after 1978.

87. While in theory some additional recovery from this reservoir may have been possible by means of the installation of pumps, in the absence of any evidence that IMINOCO considered that possibility at any time after production from the reservoir ceased in January 1975, it seems doubtful that a buyer of the Claimant's JSA interests in 1979 would have reasonably anticipated such production during the remaining life of the JSA.

(4) Rostam Arab C

88. The Claimant asserts a total recovery of 363,000 barrels of oil from this reservoir from 1979 through 1983, at which time it anticipates that the only well producing from the reservoir, AR-24, would cease such production as it would be converted to production from the Shuaiba reservoir

as part of the water-injection, secondary recovery project. The Respondents foresee a total recovery of 328,000 barrels during the same period and, as they do not agree that the Shuaiba secondary recovery project would be implemented, a total recovery of 457,000 barrels from 1979 through 1986.[34]

89. The Parties are in virtual agreement on the appropriate decline rate to apply to the years after 1979 (just under 10 percent), and the rather small difference between the Parties with respect to recovery during the 1979-1983 period results largely from different assumptions concerning the rate of production in 1979. The evidence of actual production rates is inadequate to confirm either assumption, although it does suggest that the Respondent's assumption would be too low.

90. Consistent with the conclusion, above, that the Rostam Shuaiba secondary recovery project would have been seen in 1979 as capable of being implemented by 1984, it follows that production from the Arab C reservoir would cease at that time.

91. Therefore, a total of approximately 350,000 barrels of oil would have likely been thought recoverable from this reservoir during the remaining life of the JSA.

92. In conclusion, it appears reasonable that the total oil recoverable through both primary and secondary methods from the Rostam Field as a whole would reasonably have been estimated by a buyer in 1979 at approximately 125,350,000 to 130,350,000 barrels. Consequently, the total oil recoverable from both the Rakhsh and Rostam Fields during

[34]Core Lab predicts recovery of 364,000 barrels from 1979 through 1983, and ECL foresees recovery of 519,000 barrels from 1979 to 1999.

the remaining life of the JSA would reasonably have been estimated in 1979 at approximately 279,000,000 to 293,000,000 barrels.