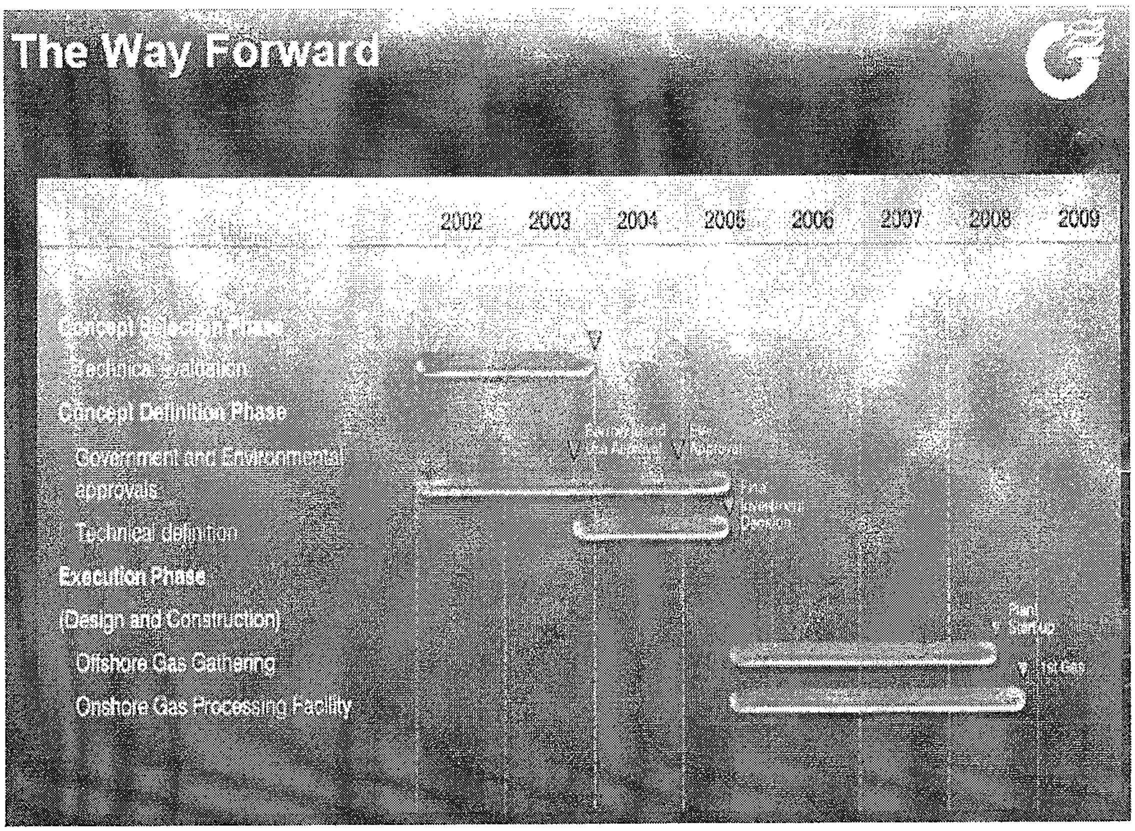
- CO_2 pipeline and sequestration system – for transport and re-injection of CO_2 – on Barrow Island;

- Domestic gas infrastructure – a proposed domestic gas plant and pipeline from Barrow Island to the mainland; and

- Ancillary infrastructure – including telecommunications facilities and mainland support facilities.

202. All of these activities, including the necessary marketing, are projected to take years. A Gorgon Venture chart, from a presentation called "The Gorgon Gas Development, A Case Study in Sustainability Assessment," given at the Australian Petroleum Production and Exploration Association Ltd. Fiscal Conference on August 29, 2003, portrays the timeline graphically and dramatically:



203. Under these circumstances, the booking of approximately 557 million boe of proved gas reserves relating to the Gorgon fields, as of December 31, 1997, was improper and in violation of Rule 4-10, as Defendants were well aware (according to both the SEC, the FSA, and the GAC Report).

204. Indeed, the Companies revisited the questionable status of the Gorgon booking at several points, beginning in 1999. The GAC Report cites, for example, the January 17, 2000 decision – reviewed in a presentation to the EP Executive Committee attended by Watts – to "freeze" the booking, despite a 20% increase in technical reserves, as an initial instance where the Group reviewed the booking of reserves at Gorgon. As noted by the FSA, the January 17, 2000 presentation explained that a freeze in booking was appropriate because of "'the limited market availability and already large uncommitted proved gas reserves.'" It further warned that "proved gas volumes in Australia have been a point of challenge by the external auditors . . . for the last two years and incremental booking at present would be hard to support." (Emphasis added.) In October 2000, the GRA affirmed this "freeze" status, against a local technical opinion in favor of de-booking. In 2002, the GRC concluded that the Companies should maintain Gorgon as proved reserves unless it was "absolutely clear that development will not proceed in a reasonable time frame." While de-booking continued to be debated, no action was taken until January, 2004. Indeed, between 1999 and January 9, 2004, according to the SEC, the Group "reevaluated whether to maintain Gorgon's 'proved' status." Significantly, as noted by the SEC, "[d]uring this time, Shell learned that none of its partners in Gorgon had booked proved reserves in the field."

205. By no later than 2002, as the SEC found, "Shell's EP personnel recognized that Gorgon was a 'dodgy' booking whose status as proved reserves was not supportable even under Shell's lenient 2002 internal reserves guidelines." Consequently, the Companies attempted to

manage the Gorgon reserves as a means of de-booking the reserves as proved: "In March 2000, Shell's Australian affiliate was instructed by regional Shell management to review options for gradually de-booking Gorgon proved reserves, such as by offsetting Gorgon de-bookings against then-anticipated new proved reserves bookings in Shell's Sunrise natural gas field in the Timor Sea." But, as set forth in the GAC Report: "In the words of the current Group Reserves Coordinator [John Pay], Gorgon had long 'stuck out like a sore thumb', but, at over 500 million boe, de-booking of the reserve was 'too big to swallow.'" To date, as noted in the SEC Complaint, "[n]o gas from Gorgon has ever been sold or firmly contracted for [sale], and Shell has yet to make a final investment decision to develop Gorgon's hydrocarbons."

2. <u>Nigeria</u>

206. Nigeria is rich in hydrocarbons. As noted by the SEC, "Nigeria represents one of Shell's largest worldwide concentration of reserves and production."

207. The development of the petroleum industry, which began in the late 1950s in the Niger Delta, gained momentum in the late 1960s and 1970s, radically transforming Nigeria from an agriculturally based economy to a major oil exporter. In 1971, Nigeria joined OPEC, and the State-owned Nigerian National Oil Corporation ("NNOC") was established. In 1977, the NNOC became the Nigerian National Petroleum Corporation ("NNPC"), the giant corporation that dominates all sectors of the oil industry, both upstream and downstream.

208. Since the late 1970s, the oil and gas industry has been the backbone of the Nigerian economy, accounting for over 90% of total foreign exchange earnings. Nigeria is the world's thirteenth largest producer of crude oil and natural gas liquids and the largest producer and exporter in Africa. In 2001, for example, crude oil production averaged 2.22 million barrels per day. At January 2002, the country's proved reserves were estimated at 24 billion barrels of oil

and condensates and gas reserves of 3,610 billion cubic meters, which is approximately 30% of African oil and gas reserves. These reserves are mainly from onshore fields on both dry land and swampy areas of the Niger Delta.

209. During the 1990s, the Nigerian deep and ultra-deepwater areas became the focus of major exploration by foreign oil companies with encouraging success. The first such success came in 1993 with the discovery of the Bonga oil and gas field.

210. The Bonga field is the first deepwater project for the SPDC and for Nigeria as a country. SPDC operates the field on behalf of the NNPC under a production-sharing contract, in partnership with Esso (ExxonMobil) (20%), Nigeria Agip (12.5%), and Elf Petroleum Nigeria Limited (12.5%). Defendant Watts announced the discovery of the Bonga field in 1999, when he served as head of EP.

211. The Bonga field lies 120 kilometers south-west of the Niger Delta, in water more than 1,000 meters deep. After acquiring, processing, and interpreting 3D seismic data in 1993/1994, the first Bonga discovery well was drilled between September 1995 and January 1996.

212. In May 2001, the SPDC drilled an exploration well on Bonga South-West ("Bonga SW") located approximately 10 kilometers south-west of the Bonga Field. Bonga SW was drilled in a water depth of 1,245 meters. The well reached its final depth of 4,160 meters and was subsequently logged and suspended.

213. The SPDC used a deep-sea floating production, storage, and off-loading vessel (the "Bonga FPSO") to extract, refine, and produce the oil and gas in the Bonga field. The Bonga FPSO is capable of producing 225,000 barrels of oil per day, exporting 150 million standard cubic feet of gas per day, and storing up to two million barrels of oil. Oil production will be transferred

from the onboard storage tanks to tankers and the gas to an offshore gas-gathering pipeline for eventual liquefaction at the Nigeria Liquefied Natural Gas plant at Bonny Island.

214. The Bonny Island facility was completed in September 1999. The Nigeria Liquefied Natural Gas Corporation, which is comprised of the NNPC (49%), the Companies (25.6%), TotalFinaElf (15%), and Agip (10.4%), operates the Bonny Island facility. Natural gas from dedicated fields initially supplied the facility with gas for conversion into LNG. However, since 1999, the facility has also converted associated natural gas to LNG.

215. The Bonga field is the largest oil field in Nigeria with an estimated output of more than 225,000 barrels of crude oil per day. The Bonga project was originally set to come on stream in 2003. The Bonga field is estimated to contain 600 million boe. Analysts expected that Nigeria would deliver 33% of the Shell Group's production increases through 2007.

216. Although the Bonga project was set to come on stream in 2003, extraction and production of the field was beset with problems (e.g., issues with the construction of the Bonga FPSO (such as leaks in the hull) and its installation in Nigeria (the Bonga FSPO left Newcastle, England on October 19, 2003, for Nigeria (with no propulsion system of its own, the vessel had to be towed)), infrastructure issues, compliance with government mandates, lack of adequate government funding, and ethnic unrest) that made proved reserves classification improper and in violation of SEC guidelines. As shown in the Cease and Desist Order, the Notice to Take Action, the GAC Report, and the news media, Defendants knew of these problems, and knew that the booking of reserves was unreasonable and improper.

217. By 1999, the SPDC had booked proved reserves based upon the Shell Group's 1998 revised guidelines and forecasts that, as the SEC noted, "gave the appearance that the proved portion of the reserves could be produced within the remaining license period." Their

forecasts were predicated on myriad assumptions, rather than existing conditions as required by SEC rules, concerning Nigeria's economic stability and increased production quotas from the Nigerian government and OPEC. As the SEC found, however, "none of these assumptions was reasonable, particularly in light of the fact that SPDC's operations performed well below the projected levels throughout the period."

218. EP management was advised in the January 17, 2000 presentation that a substantial part of SPDC's reported proved reserves (in excess of 600 million boe) was constrained by license expiration and depended on unrealistic production forecasts that appeared to have been "reverse engineered" solely to support the reserve figures. The presentation also concluded that the Group's 1999 RRR was 37%. According to the SEC and FSA, however, "EP management forcefully rejected this conclusion and instead caused Shell to report a 56% RRR for that year."

219. The GAC Report also spoke of the January 17, 2000 presentation. According to the GAC Report, no later than early 2000, EP management was aware that a substantial amount of proved reserves booked by SPDC "could not be produced as originally projected or within its current license periods." Incredibly, management decided, "[r]ather than de-book reserves, an effort was undertaken to manage the problem through a moratorium on new oil and gas additions, in the hope that SPDC's production levels would increase dramatically to support its reported reserves."

220. The following month, the GRA submitted his report on the Group's 1999 proved reserves, wherein he repeated the foregoing concerns, noting that SPDC faced license expiration problems and could support its proved reserves figures only through "significant aspirational upturns in future offtake levels in order to justify their proved reserves levels." The SEC found

that the GRA "repeated these concerns, without EP taking any steps to de-book non-compliant reserves. . . ."

221. By early 2002, according to the SEC, "other Shell reserves personnel, including the Group Reserves Coordinator, had raised concerns within EP that SPDC's reported proved reserves could not be produced within existing license constraints."

222. Thereafter, according to the SEC, "EP management continued to review the technical and commercial maturity of SPDC's reserves. After completing the initial phase of its work in September 2003, the EP review team concluded that there was an approximately 750 million boe 'gap' between the reported proved reserves and those supported by projects in the business plans." Also in September 2003, the GRA reported the results of his just-completed audit of SPDC's proved reserves, concluding that "there can be no doubt that the portfolio of proved oil reserves per [January 1, 2003] has been overstated due to insufficient maturity in the underlying future projects." As noted by the SEC, the GRA indicated that "the 'precise' amount of de-booking required was dependent on additional reviews already underway by EP."

223. By November 2003, the EP review team completed the second phase of its work. As noted by the SEC, "[i]t confirmed the earlier findings of a 750 million boe 'gap' and added another 800 million boe of proved reserves that were not sufficiently mature under Shell guidelines."

224. Management also decided that it would conceal the reserves problem from the investing public. As noted in the news media, the December 8th Report recommended that "any debooking of proved reserves" in Nigeria should "not be identified publicly with Nigeria," but classified under a wider geographic area. Accordingly, in February 2004, the Shell Group reported reserve information about Nigeria in the context of its African operations, which it said

accounted for 1.5 billion barrels of the revision. The Shell Group has operations in several African countries, including Libya and Egypt, but, as reported in THE NEW YORK TIMES on March 19, 2004, Nigeria is the only country listed in a "potential reserves exposure catalog" that was distributed to senior executives late last year.

a. <u>Poor Infrastructure Slowed Recovery</u>

225. Oil fields require a large infrastructure to produce, process, and transport the hydrocarbons to market. As the Shell Group brought new oil wells on line, each required capital expenditures and commitments to infrastructure to process and transport the oil and liquid natural gas. As alleged above, by no later than 2000, EP management knew that the SPDC had been encountering infrastructure and transportation problems that made the booking of proved reserves improper.

226. Beginning in 1997, the Nigerian government mandated that natural gas flaring end by 2008 and that these resources be captured. Flaring is a means of disposing of waste hydrocarbon gases by burning them. With an elevated flare, the combustion is carried out through the top of a pipe or stack where the burner and igniter are located. Flaring adversely affects the environment by, among other things, releasing sulphur oxides into the atmosphere, when the gas contains sulphur.

227. The Companies stated that they were committed to meeting the 2008 target to cease flaring and planned to recapture the gas for sale. The Shell Group's website stated that "this opportunity [to gather gas] is going well." The Companies stated that they planned to integrate oil and gas production, that they had three production processing trains fully operational, and that they were building additional trains to meet the deadline.

228. The end of flaring required new investments in infrastructure of older oil production facilities to meet Nigeria's mandate. However, according to THE NEW YORK TIMES on March 19, 2004, many oil field projects did not include plans to gather natural gas, and oil production would have to be stopped unless the Companies found a way to use the gas. Van de Vijver conceded as much in a February 5, 2004 conference with market analysts: "it is clear that the growth production onshore in Nigeria is less than what we and what the government had hoped five/ten years ago, and it's all linked with the complexity of putting the integrated oil and gas development together, building the gas infrastructure and not only to collect and compress the gas, but also to transport it over the vast onshore delta and also ultimately bringing to Nigeria and the LNG."

229. The GAC Report observed that in Nigeria, there was "a significant decrease in the reserve 'offset' supposedly available due to 'fuel and flare.'"

b. <u>Lack of Governmental Financing Slowed Recovery</u>

230. A major problem facing Nigeria's upstream oil sector has been insufficient government funding of its joint venture commitments. As reported in THE NEW YORK TIMES on March 19, 2004, in November 2003, the International Energy Agency (the "IEA") found that joint ventures – like Shell Transport's in Nigeria, where it is in partnership with the government – "suffered from underinvestment, because of a lack of state funding." Under the joint venture arrangements, the Nigerian government and its partners contribute to these projects according to their equity holding. According to the IEA and to local news media reports, government budget and other developments had shifted more of the financial burden of developing oilfields to foreign investors.

231. The 2002 SPDC Annual Report is illustrative of the funding problems that faced the SPDC. The report stated that "2002 was a challenging year. The Federal Government allocated a budget of $3.2 billion to the oil industry to fund the Nigeria National Petroleum Company's (NNPC's) interest in joint ventures. This was lower than the 2001 budget and well below the level requested by the industry."

232. The report also stated that "[t]he budget constraint led to a major reduction in investments to increase oil production capacity, improve infrastructure and increase reserves. Also, we experienced serious difficulty in paying our contractors and suppliers, and we incurred delays in settling outstanding invoices to third parties." Nevertheless, the SPDC booked a portion of the reserves as proved.

c. <u>Political Unrest and Delay Slowed Recovery</u>

233. In addition to financial issues, political and ethnic strife in the Niger Delta region, including violence, kidnapping, sabotage, and the seizure of oil facilities, contributed to the Companies' inability to manage reserves. As reported in the December 8th Report, "Community disturbances and political instability" were also to blame. Much of Nigeria's oil reserves are located in the delta region in the south, where unrest forced the Companies to reduce production.

234. In early March 2003, for example, the Shell Group removed its non-essential staff and later shut down its operations in the Niger Delta region, evacuating all personnel, on March 19, 2003. The Companies closed their flow stations, which had a combined capacity of 126,000 bbl/d. The Group later evacuated four oil facilities – oil pipeline pumping stations at Ogbotobo, Opukushi, Tumo, and Benisede – on March 24, 2003, raising the number of closed Group facilities to 14. These actions shut-in 320,000 bbl/d, or nearly one-third of the Shell Group's Nigerian output.

d. The Need To Protect OPEC Interests

235. Internal documents show that the Shell Group concluded that more than 1.5 billion barrels, or 60% of its Nigerian reserves, did not meet SEC standards for proved reserves. The scale of the revision is important because Nigeria is seeking to increase its production quota within OPEC. As CS 4 has explained, the size of proved reserves is a basic consideration when OPEC sets quotas for its members. At stake for Nigeria are billions of dollars in revenue annually.

236. According to the December 8th Report, identifying the extent of the Shell Group's lowered reserves in Nigeria could affect Nigeria's "quota discussions" with OPEC. Nigeria had been seeking a quota increase as part of a plan to double its daily production in the next several years.

237. As reported by the news media, the reserves reclassification also relates to OPEC restraints. THE TIMES [LONDON] reported on January 10, 2004, that the Shell Group was unable to comply with Nigeria's OPEC quota. Consequently, the "[C]ompany should not have booked reserves of oil that Nigeria was unable to export."

238. Shell Group executives were acutely aware of the potentially explosive political effect of their cutting their estimates of Nigerian reserves. In the December 8th Report, which was prepared for senior executives, such as van de Vijver, the authors recommended that the revised Nigerian reserves remain "confidential in view of host country sensitivities."

239. Internal documents show that in April 2001, the Group submitted papers to Nigerian authorities, forecasting production increases of as much as 70% by 2003. Another set of documents prepared between 2001 and 2003 showed increases in reserves booked with the government based largely on data reviews, rather than new wells. (See FINANCIAL TIMES, April 15,

2004.) Data reviews, however, do not generally suffice to satisfy the SEC's requirements for classifying a reserve as proved.

240. According to Jonathan Bearman, managing director of Clearwater, a consulting firm that does business intelligence work in Nigeria, "Concerns had been growing among Nigerian oil officials for some time. There were quite big claims made about total reserves and Shell accounted for a large part of that."

241. Bearman also said that concerns were raised in mid-2003 after the Nigerian government's annual independent audit of its partnerships with the Shell Group and other oil producers. Issues raised included the Group's aggressive production growth estimates and the number of reserves the Companies were booking with the government, going back as far as five years.

242. At the end of 2002, the Shell Group recorded 2.524 billion barrels of proved reserves in Nigeria, but as the December 8th Report found, only 990 million barrels "fully complie[d]" with SEC guidelines. Internal documents show that senior managers were told in December 2002 that 720 million barrels in Nigeria were "noncompliant" with guidelines established by the SEC, and that a further 814 million barrels were "potentially noncompliant."

e. Nigeria's Reserve Addition Bonus

243. The December 8th Report stated that the publication of too much information concerning the lack of reserves could jeopardize the Companies' negotiations with Nigeria over $385 million in bonus payments.

244. From 1991 to 1999, Nigeria offered the Companies and other foreign oil companies an incentive to increase reserves, called a Reserves Addition Bonus ("RAB"). As noted by THE LONDON TIMES on March 21, 2004, "The Nigerian government offered oil companies

tax breaks from 1991 to 1999 for oil-reserve additions – or any oil reserves added over and above what they expected to find."

245. According to the December 8th Report, the Group claimed that it was owed $385 million under the bonus program, but had only sought 30% to 50% of the claim.

246. According to the December 8th Report, van de Vijver said that while in principle a debooking of S.E.C. proved reserves should not impact on RAB, a debooking would "likely . . . undermine the current resolution process, or would jeopardize relations if a settlement were agreed just ahead of a de-booking," adding that this would put $115 million to $170 million "at risk."

3. <u>Oman</u>

247. Oman is atypical of Persian Gulf oil producers. Its oil fields are generally smaller, more widely scattered, less productive, and more costly per barrel than those of other Persian Gulf countries.

248. The Shell Group has been involved in developing Oman's natural resources since oil was first discovered in Oman in the 1930s. The Group owns 34% of PDO, Oman's dominant oil and gas exploration company. The other partners in PDO are the Omani government (60%), Total (4%), and Partex (2%). PDO accounts for 90% of the sultanate's oil production and virtually all of its natural gas production.

249. According to PDO, the bulk of Oman's oil reserves are located in the country's northern and central regions. Oman's largest oil reservoir is a mature field called Yibal.

250. Oil production in Oman has declined since 1997. In 2003, PDO estimated that Oman had less than 20 years left as a major oil-exporting nation. Estimates also suggest that Oman has approximately 40 billion barrels of oil that have not been recovered. Accordingly,

finding ways to increase recoverability is a top priority. For Oman to produce additional oil out of its mature fields, PDO employs a variety of enhanced oil recovery ("EOR") techniques, such as horizontal drilling.

a. <u>Horizontal Drilling Did Not More Efficiently Recover Reserves</u>

251. In the last 10 years, horizontal drilling has become one of the most important innovations in the oil production business and is widely used around the world. The Group claims that, properly managed, horizontal drilling can extract a higher percentage of oil from certain fields, and recover oil more efficiently than traditional vertical drilling.

252. Horizontal drilling creates lateral wells that contact more reservoir volume than a traditional single vertical well. In Oman, both oil and water were produced from the wells, and the oil is separated from the mixture in surface facilities.

253. The December 8th Report found that using horizontal wells did not increase the amount of oil that will ultimately be recovered from the reservoir. In Oman, horizontal drilling resulted in large amounts of water being produced with the oil, in contrast to the original expectation that less water would be produced with the oil. This result demonstrated that although horizontal drilling may work in some places, it may not always be the answer to declining production rates in some of the mature fields of the Middle East.

254. An example of the failure of horizontal drilling is demonstrated by the Yibal field. The declines in the Yibal field were detailed by PDO officials in two papers published in 2003 by the Society of Petroleum Engineers (SPE 84939 and SPE 81489). The papers stated that about 90% of the liquid coming out of the Yibal field was water and only 10% was oil. The high volume of water, one paper said, comes in part from the water that the Companies injected into the reservoir as part of their overall pressure maintenance recovery scheme employed at Yibal.

This high volume of water being produced adds considerably to the costs and delay of extracting the oil.

255. The two engineering papers also show that production in Yibal had fallen at an annual rate of about 12% for six years – more than twice the normal rate of 5% in the region. Additionally, the papers agree that production peaked in 1997 and declined more than 50% by 2000.

256. As reported in THE NEW YORK TIMES on April 8, 2004, internal Group documents confirm that production at the Yibal field began to decline rapidly after 1997. Yet, Watts, in his remarks on May 29, 2000, continued to talk positively about the effect of horizontal drilling and other technologies at Yibal, saying it was "still the country's most important producer three decades after coming on-stream."

257. Since 2000, PDO missed production and reserve targets for three consecutive years. In PDO's 2000 Annual Report to Sultan Qaboos bin Said, Sultan of Oman, PDO reported that it had planned "to increase the production of black oil by 18,000 barrels per day (b/d) in 2000, to a record level of 850,000 b/d. This ambitious growth target proved to be too challenging. The black-oil production during 2000 averaged 840,000 b/d, that is, 8,000 b/d higher than the 1999 production level but 10,000 b/d below the target."

258. PDO's 2001 Annual Report to Sultan Qaboos bin Said, Sultan of Oman ("PDO 2001 Report") stated that: "We missed our oil production target by 2% in 2001. This shortfall may appear small in percentage terms, but it is important for the Sultanate, which still relies to a large extent on PDO's oil production. We realised in 2001 that our reservoirs are becoming mature and that the emphasis of the Company has to move away from drilling wells to more active reservoir management and ultimately to enhanced oil recovery (EOR) techniques."

259. The PDO 2001 Report also stated that, "[i]n 2001 a total of 151 million barrels of black oil were added to the Company's reserves, falling well below the target of 410 million barrels." Because PDO produced a total of 303 million barrels of oil over the year, black-oil reserves declined by 152 million barrels, representing a drop of 3%. At the end of 2001, black-oil reserves stood at 4.862 billion barrels.

260. Shortfalls in production and reserves were also seen in 2002. PDO's 2002 Annual Report to Sultan Qaboos bin Said, Sultan of Oman, stated that PDO missed oil production targets by 44,000 barrels of oil per day and was short of oil reserve additions. After three years of missing production and reserve targets, PDO reduced its 2003 production target and its reserve addition target from old oil fields.

b. <u>Shell Management Increased Oman's Reported Reserves</u>

261. By the end of 2000, despite the production decline in Oman, the Group and PDO determined to increase PDO's proved reserves estimates. Based on the 1998 revisions to the Shell Group's guidelines, the Companies revised PDO's proved reserves upward "by assuming that, for fields of certain maturity, both proved developed and proved undeveloped reserves would be increased to equal the expectation developed and undeveloped volumes." The increase added 251 million boe to the Shell Group's reported proved reserves at December 31, 2000. Internal Group documents show that the figure for proved oil reserves in Oman was improperly increased in 2000, resulting in a 40% overstatement.

262. In mid-2001, PDO began to experience a steep decline in production. Within a few months, the situation had grown sufficiently worse, causing PDO to withdraw its long-term business plan for 2002. As noted by the SEC in the Cease and Desist Order, "[t]he production decline also prompted the Omani government to question the volume of expectation reserves

PDO was carrying, as a result of which Shell agreed to a $30 million 'down payment' to the Omani government on what was expected to be an eventual refund of expectation reserve booking fees it previously had received." By the end of 2001, as production continued to decline, PDO operated without a reliable or realistic long-term business plan on which to base its proved reserves reporting. According to the SEC, "[w]ith Shell's encouragement, PDO instead adopted an 'aspirational' production forecast to support its reported proved reserves figures."

263. As explained in the Cease and Desist Order, during 2002, the Companies were advised that PDO's proved reserves figures "depended upon sustaining current production rates, without any declines, throughout the remaining lifetime of the production license, which was to expire in 2012." As noted by the SEC, "[i]n view of the production declines already being experienced, this was not realistic. Shell nevertheless continued to report its share of PDO's reserves as proved at year-end 2002."

264. These events were confirmed in the GAC Report. According to the GAC Report, the reserve overstatement stemmed from insufficient technical work that was done to support the increase in reserves. When serious production declines were suffered thereafter, these increased reserves were maintained based upon aspirational production targets. The GAC concluded in its report that various members of EP management, including Defendant van de Vijver, were aware of the matter when the production problems increased, and the Companies agreed to make the $30 million down payment (in the form of a deduction against its 2001 net reward) in partial payment for an inchoate debooking of expected reserves.

265. The Shell Group's interest in increasing shareholder value in the short-term played a part in the overvaluation of the reserves: because its license in Oman expires in 2012, it emphasized producing more oil sooner. Indeed, the December 8th Report stated that "the extreme

focus on short-term development opportunities ('keep the rigs busy to keep the oil rate up') to the detriment of defining long-term projects" also drained Oman's reserve pool.

266. In the December 8th Report, the Shell Group recommended that the lowered amount of Oman's proven reserves be kept confidential because of the nexus between reserves and bonus compensation. As reported by THE NEW YORK TIMES on April 8, 2004, "according to the report, [proven reserve figures] involve[ ] negotiations over bonuses that the company can win for increasing reserves. The basis for the bonus is a less rigorous standard – called expectation reserves – than the proven-reserves yardstick that the Company is required by the SEC to list in periodic filings." The December 8th Report said that "the expectation reserves may be overstated."

267. The December 8th Report also said, "With hindsight, it might have been more appropriate to correct the expectation estimate down rather than the proved estimate upwards." The report said that it was understood at the time when the reserve estimate was increased that a more detailed assessment would follow. But it was not until 2003, four years after the previous audit, that the Shell Group did an audit of proved reserves of its operations in Oman. As a result, "[p]roved total reserves are currently overstated by some 40 percent."

268. As alleged herein, the Shell Group reclassified 2.3 billion boe due to "project maturity in existing producing areas," such as Nigeria and Oman. In Oman, 393 million boe of proved reserves associated with PDO had to be de-booked as noncompliant with SEC rules. The SEC found that "[o]f this amount, 144 million boe were non-compliant because they were 'associated with projects . . . not sufficiently mature to qualify as proved undeveloped reserves.' The remaining 249 million boe were non-compliant because they were not supported by any identified projects."

4. **Norway (Ormen Lange)**

269. The Ormen Lange field, named after a large Viking ship celebrated in Norse sagas, is located in the Norwegian Sea, approximately 140km west of Kristiansund, Norway. The field is the second-largest gas discovery on the Norwegian continental shelf. The discovery well was drilled in 1997. The field contains estimated resources of 315 billion cubic meters ("m^3") of natural gas. The main gas reserves lie in a reservoir in the Egga interval.

270. Licenses for the development and production of the field are held by the following project partners:

- Norske Shell ("Shell Norway"): 16% (production operator)
- Norske Hydro Produksjon ("Norske Hydro"): 14.78% (drilling operator)
- Statoil: 8.87%
- State's Direct Financial Interest (SDFI): 45%
- BPAmoco Norge ("BP"): 9.44%
- Esso Norge ("ExxonMobil"): 5.91%

271. Norske Hydro and Shell Norway share operator responsibilities for the field. Norske Hydro is responsible for the development phase of the project, while Shell Norway is responsible for developing the transport of the gas and all the commercial relationships, and for operating the field during its producing life.

272. Planning and development of the Ormen Lange field has been described as one of the most challenging assignments that a group of oil companies has ever undertaken, not just in Norway but worldwide. Indeed, since 1997, the project partners have encountered technical challenges involving harsh deep-water conditions, harsh weather conditions, freezing water temperatures, and an uneven seabed.

273. The Ormen Lange field lies in water depths of 800-1200 meters, close to the steep back wall left by the Storegga submarine slide, which occurred 7,000-8,000 years ago. The Storegga slide was triggered by a major earthquake and weak sedimentary layers.

274. The Storegga slide created a 10-20 meter high tidal wave that reached the Norwegian and British Isles coasts. The mass slid about 800 kilometers into the deep sea, and its back edge is around 300 kilometers long. As shown in the picture that follows, the Ormen Lange field is in the middle of the depression left behind by the Storegga slide and is close to the steep slide edge, which rises 200-300 meters up towards the continental shelf. The gas in the field cannot be reached by wells that might possibly be drilled from outside the slide area.

275. According to Norske Hydro, "The Storegga slide seabed is undulating, with local elevation[ ] [variations] of up to approximately 50 m to 60 m (164 ft to 197 ft) above [the average] seabed level." Further complicating development and production is the variable seabed soil, which varies between hard and soft.

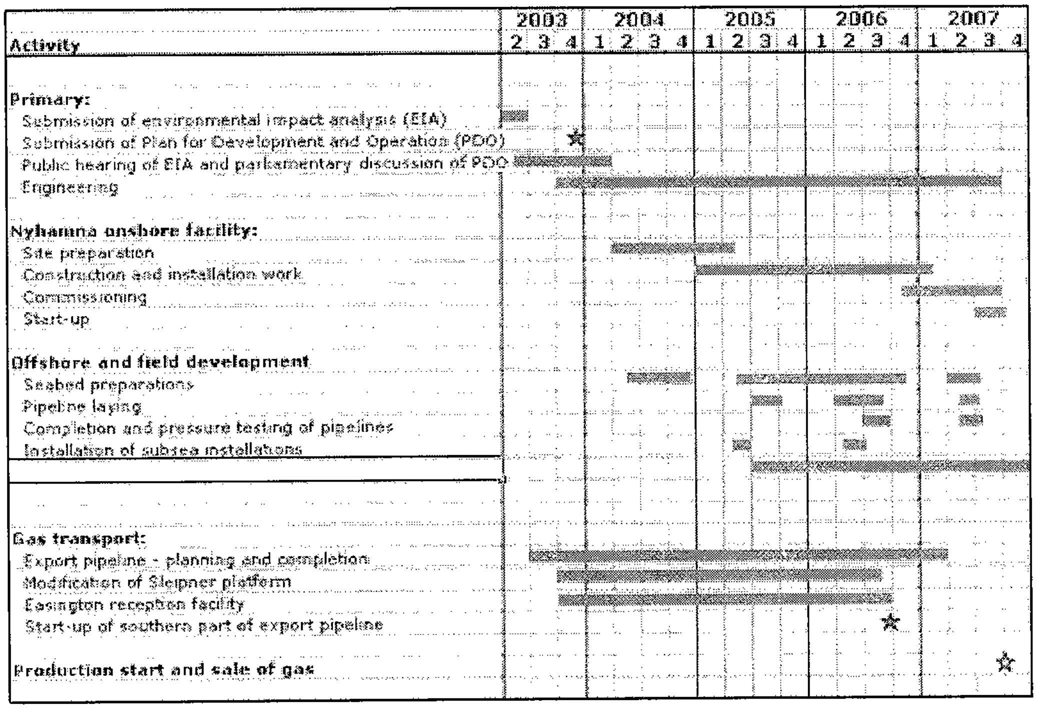
276. Any new subsea export pipeline from the field location has to traverse this complex sea bottom topography and then rise up the seabed escarpment to a higher plateau – a

height of at least 1,640 ft (500 m). Effectively, this means building a pipeline up a subsea cliff face.

277. The planning and design of a reliable and safe pipeline route has required a significant feat of engineering. According to Norske Hydro, it was not until "early 2002" that the project partners were able to identify "a pipeline route out of the slide area and up the escarpment."

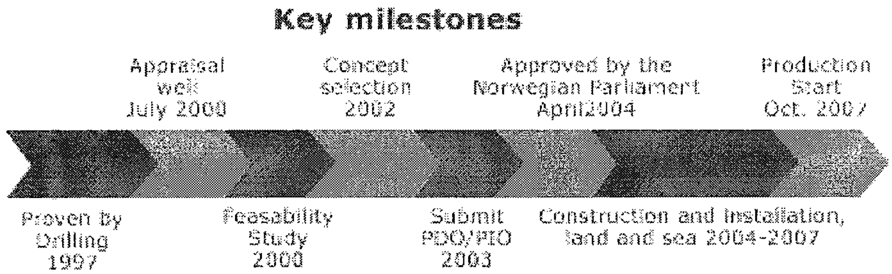
278. According to the news media, the project partners were very concerned that the pipeline construction activities might trigger another major slide event. Consequently, they conducted a $100 million study to establish its safety. This study began in early 2000, and was completed in mid-2003, when it found the project safe to proceed.

279. In June 2001, the project partners decided to modify the timeframe for developing the field. According to Bengt Lie Hansen, Norske Hydro's head of the mid-Norway sector of Exploration and Development, "Studies and tests show there's a need to use more time mapping and doing essential preliminary work to determine the best concept and to optimize well placement. The area's complex sea topography and extreme subsea conditions . . . prolonged the process of gathering and evaluating data associated with the pipeline route." Even as late as 2003, the project's partners were still struggling to determine whether European markets could absorb the supply of natural gas from the field. Consequently, the project partners extended the schedule for delivery of the plan for development and operation ("P.D.O.") to the Norwegian authorities until the fall 2003. The slide below (taken from the Ormen Lange website) illustrates the project's new time table:



280. The P.D.O. for the Ormen Lange gas field was submitted to the Ministry of Petroleum and Energy on December 4, 2003, together with the Plan for Installation and Operation for the new subsea gas export pipeline, named Langeled, to the United Kingdom. The Norwegian government did not approve the submissions until April 2, 2004. As shown in the above timetable, production start-up is now projected to commence in the fall of 2007.

281. Unlike its project partners, the Companies began booking reserves from the Ormen Lange field years before the Shell Group and its partners could work out the difficult technical and marketing hurdles on the project. Indeed, in 1999, just two years after the field was discovered, the Companies started booking gas reserves even before an appraisal well was drilled or a feasibility study conducted, let alone the safety study discussed above:



282. According to Thor Tangen, senior vice president with Norske Hydro and the project's director until January 2004, when the Shell Group booked the Ormen Lange reserves in 1999, the project partners had drilled just two exploration wells and done some preliminary feasibility studies. The Shell Group relied on three dimensional ("3D") seismic data to book reserves before additional delineation wells were drilled, which is not sufficient to satisfy SEC guidelines. As reported in the May 20, 2004 edition of ACCOUNTANCY, "Shell flow-tested two wells then used 3D seismic technology to say it had proved reserves between the two, rather than drill an additional well that could quite easily have cost $20 [million]."

283. Of the Ormen Lange partners, only the Shell Group booked reserves as proved. Norske Hydro, Statoil ASA, BP, and ExxonMobil all held off booking reserves from Ormen Lange until December 2003/early 2004. The Shell Group's proved reserves booking from Ormen Lange eventually grew to approximately 109 million boe.

D. <u>Internal Control Deficiencies</u>

284. The Shell Group maintains a system of internal controls for which management in the Group is responsible for implementing, operating, and monitoring. According to the Shell Group's Form 20-F's, the Conference regularly reviews the overall effectiveness of the Shell Group's system of internal control and performs a full annual review of the system's effectiveness.

285. At the Group level and within each business, risk profiles that highlight the perceived impact and likelihood of significant risks are reviewed each quarter by the CMD and by the Conference. Each risk profile is supported by a summary of key controls and monitoring mechanisms.

286. The Shell Group has represented that it enforces its system of internal controls through a number of general and specific risk management processes and policies. As set forth in the Form 20-F's, "the Group's primary control mechanisms are self-appraisal processes in combination with strict accountability for results. These mechanisms are underpinned by controls including Group policies, standards and guidance material that relate to particular types of risk, structured investment decision processes, timely and effective reporting systems and performance appraisal." Further:

> An explicit risk and internal control policy was approved by the Boards of the Group Holding Companies in December 1999. This policy states that the Group has a risk-based approach to internal control and that management in the Group is responsible for implementing, operating and monitoring the system of internal control, which is designed to provide reasonable but not absolute assurance of achieving business objectives.
>
> Consistent with this policy and with published advice on best practice, existing processes are being strengthened and formalized to bring into greater focus the identification, evaluation and reporting of risk as an integral part of the system of internal control. As part of their existing planning processes, businesses will now consolidate and report risk profiles, critical risk response summaries and descriptions of how risk and control management effectiveness will be monitored. In addition to existing ad hoc reporting mechanisms, the Committee of Managing Directors will receive regular updates on this information during quarterly business performance reviews, and will also consider the risks associated with objectives and long-term plans. The results of this work will be presented to Conference (meetings between the members of the Supervisory Board and the Board of Management of Royal Dutch and the Directors of Shell Transport) on a quarterly basis.

1999 Form 20-F.

287. Additionally, the Shell Group relies on both internal and external audit functions to ensure the effectiveness of its control systems.

288. The false and misleading booking of "proved reserves" was possible because of material internal control deficiencies in the Shell Group's internal financial and accounting controls, which Defendant van de Vijver recognized violated the disclosure requirements of the U.S. securities laws. As noted in the GAC Report: "The booking of aggressive reserves and their continued place on Shell's books were only possible because of certain deficiencies in the Company's controls." The GAC Report cites, as an example, the understaffing of the internal reserves audit function: "This function was performed by a single, part-time, former Shell employee; his cycle of field audits was once every four years; he was provided with virtually no instruction concerning regulatory requirements, or the role of an independent auditor and no internal legal liaison." According to CS 1, the GRA was "normally a sinecure for a former senior reservoir engineer, [who] had neither the time nor the resources to challenge operating company submissions. Audits were carried out but their principal purpose was to ensure that all documentation was in order rather than estimates, uncertainties, etc. being correct."

289. The GAC Report found that "[w]hile the GRA made 13 occasional attempts to bring proved reserves into compliance with both SEC rules and Shell Guidelines, he had neither the power nor facilities to insure such compliance." In fact, the GAC Report notes that the GRA "acquiesced in or attempted to assist Shell in 'managing,' rather than debooking, its nonqualifying reserves." Examples cited are the moratoria in Australia and Nigeria and the GRA's advice not to de-book the 40% non-compliant Oman reserves.

290. The deficiencies in the GRA's auditing function were so severe that, as the SEC found, between 1999 and September 2003, the GRA never issued an unsatisfactory report

concerning the Shell Group's compliance with its reserve reporting guidelines. This result is not surprising given the lack of independence of the GRA. As the SEC found in the Cease and Desist Order: "Moreover, he reported to EP management, meaning he was answerable to the same people he audited."

291. The GRA's lack of independence permitted the Shell Group's classification of reserves associated with a project to remain as proved, and, as the SEC found, "facilitated the booking of questionable reserves . . . and contributed to Shell's maintenance of increasingly questionable bookings (such as Gorgon and certain legacy bookings in Brunei) well after they should have been de-booked."

292. The GAC Report also observed that the Companies' guidelines "blurred the distinction between reserves reporting for internal decision-making and the requirements for regulatory reporting of proved reserves; were slow to incorporate SEC staff interpretations and, while reflecting an increased awareness of SEC rules, occasionally adopted an expedient of partial compliance; did not encourage OUs to review existing bookings for continued compliance and did not adequately address the need for debooking; and, were not clearly and succinctly written or organized to offer useful guidance to reservoir engineers in the OUs." As discussed herein, the findings of the SEC and the FSA are in accord.

293. Regarding the compliance role of the finance function, the GAC Report found that that function was not effective with respect to the subject bookings.

294. Boynton attended CMD meetings beginning in 2001 and became a member of CMD in 2003. Her responsibilities were different than other members of CMD; she had direct responsibility to ensure that the Companies' financial disclosures to the market and to regulators were correct. Boynton took virtually no action, before the initiation of the investigation that led

to the January 9th disclosure, to inquire independently into the underlying facts relating to the improper reserves bookings. Rather, Boynton relied upon the checks and balances of the Companies' representation and assurance process and the work of its independent external auditors to ensure compliance. As the memoranda prepared by Barendregt (the GRA) reveals, that process did not function properly.

E. Regulatory Actions

295. As alleged herein, various regulatory bodies have been investigating the events surrounding the reserves reclassification.

296. On August 24, 2004, the SEC issued its Cease and Desist Order, in which it concluded as follows:

a. The Companies violated Section 10(b) of the Exchange Act and Rule 10b-5 thereunder. The Companies knowingly or recklessly reported proved reserves that were non-compliant with Rule 4-10, and failed (i) to ensure that the Companies' internal proved reserves estimation and reporting guidelines complied with Rule 4-10, and (ii) to take timely and appropriate action to ensure that their reported proved reserves were not overstated in their filings with the SEC and other public statements.

b. The Companies violated Section 13(a) of the Exchange Act and Rules 13a-1 and 12b-20 thereunder. The Companies' failures to ensure that they estimated and reported proved reserves accurately in compliance with Rule 4-10 caused them to file annual reports on Form 20-F for the years 1997 through 2002 that were materially inaccurate, in that they overstated the Companies' reported proved reserves and accompanying supplemental information, including the standardized measure of future cash flows.

c. The Companies violated Sections 13(b)(2)(A) and 13(b)(2)(B) of the Exchange Act. The Companies failed to create and maintain accurate estimates of their proved reserves in compliance with Rule 4-10, and failed to ensure that they implemented and maintained adequate controls with respect to their reserves processes, sufficient to provide assurance that the reserves were estimated and reported accurately in accordance with Rule 4-10.

297. The Cease and Desist Order also states that the Companies have undertaken to spend $5 million in the development and implementation of a comprehensive internal compliance program.

298. In a separate civil action filed simultaneously with the proceeding that was the subject of the Cease and Desist Order, Royal Dutch and Shell Transport consented to the entry of a judgment by the U.S. District Court for the Southern District of Texas, Houston Division, pursuant to Section 21(d) of the Exchange Act, ordering Royal Dutch and Shell Transport, together, to pay $1 disgorgement and a $120 million civil penalty. *SEC v. Royal Dutch Petroleum Co. and The "Shell" Transport and Trading Company, p.l.c.*, No. H-04-3359 (S.D. Tex. Aug. 24, 2004).

299. Also on August 24, 2004, the FSA issued its Final Notice to Shell Transport and Royal Dutch to Take Action, in which the FSA imposed a penalty of £17 million for "market abuse" and breaches of the FSA's Listing Rules. The FSA stated that it considered the Companies' misconduct to have been "particularly serious," requiring a "substantial financial penalty," because:

- Shell announced false or misleading proved reserves and reserves replacement ratios to the market throughout the period 1998 to 2003 inclusive;

- The false or misleading reserves information was not corrected until a series of announcements between 9 January and 24 May 2004 in which Shell announced the recategorisation of 4,470 million barrels of oil equivalent, being approximately 25% of Shell's proved reserves;

- Shell's false or misleading announcements of proved reserves were made despite indications and warnings from 2000 to 2003 that its proved reserves as announced to the market were false or misleading;

- Shell failed to put in place or maintain adequate systems or controls over its reserves estimation and reporting processes; and

- Following the first announcement of its recategorisation of proved reserves on 9 January 2004, STT's share price fell from 401p to 371p (7.5%) reducing STT's market capitalization on that day by approximately £2.9 billion. On 9 January 2004 trading in the shares of STT accounted for more than 10% of the total volume of shares traded on the FTSE 100, of which STT was the seventh largest constituent by market capitalization.

FALSE AND MISLEADING STATEMENTS AND OMISSIONS

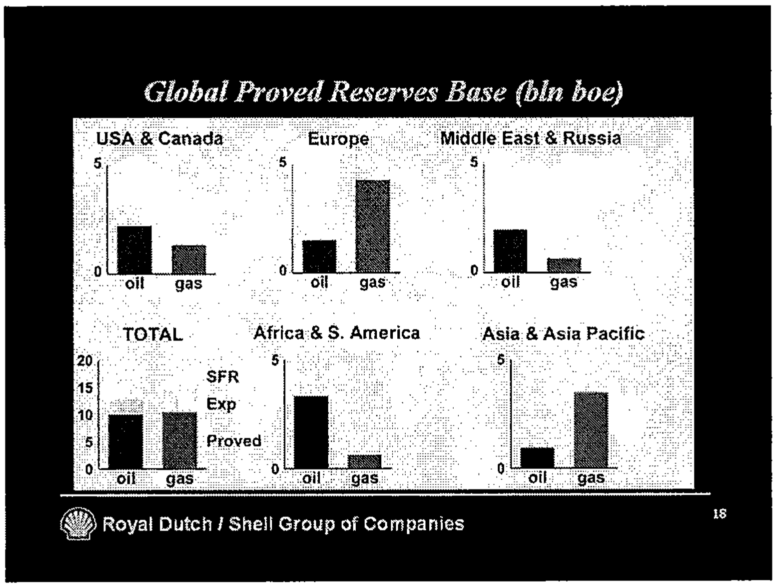
Statements Made in Second-Quarter 1999

300. On April 8, 1999, the Companies issued a press release entitled "Royal Dutch Petroleum Company and the 'Shell' Transport and Trading Company, p.l.c." According to the press release, the Exploration and Production Executive Committee, led by Watts, planned to present and discuss EP's plans and strategies before an audience of fund managers and analysts later that day in New York. The same presentation was to be given the next day in Rijswijk, in The Netherlands. The press release stated that the following points would be presented:

> ***Growth will build on the Group's extensive global resource base. The Group's proved reserves base increased by 1 billion barrels of oil equivalent from 19.4 end 1997 to 20.4 billion barrels of oil equivalent end 1998. The proved oil reserves at the end of 1998 were 10.0 billion barrels for oil and 10.4 billion barrels of oil equivalent for gas. The total resource base, including expectation reserves and scope for recovery, amounts to some 40 billion barrels of oil equivalent.*** [Emphasis added.]

301. As represented in the press release, both Watts and van de Vijver participated in a conference with fund managers and analysts in New York that same day. During the

presentation, Watts and van de Vijver discussed, among other things, the Companies' reserves and reserve replacement ratio. In the presentation materials posted on the Companies' web site, entitled "Improving Performance and Maximizing Value in Uncertain Times," the Companies' total proved reserve replacement ratio was represented to be 182%, and their proved reserves were represented as follows:



302. As Defendants knew or were reckless in not knowing, the statements in the previous two paragraphs – concerning the Companies' proved reserves and proved reserve replacement ratios – were materially false and misleading when made because Defendants failed to comply with SEC guidelines when booking proved reserves. See ¶¶ 6, 11-12, 127-42, 147, 149-84, 296, 489-91. As a result: as of December 31, 1997, the Companies inappropriately booked as proved approximately 557 million boe of natural gas relating to the Gorgon fields (see ¶¶ 187-205); beginning in the 1990s, and in particular the late 1990s, the Companies inappropriately booked volumes of proved oil in Nigeria characterized as "very large" by the GAC Report – perhaps as many as 1.5 billion barrels (see ¶¶ 206-46); according to the December

8th Report, the Companies' total proved reserves for Oman were overstated by "some 40 percent" (see ¶¶ 247-68); and the Companies overbooked proved reserves at Ormen Lange by more than 100 million boe (see ¶¶ 269-83). Over the course of the Class Period, Defendants overbooked proved reserves by 4.47 billion boe worldwide.

303. On April 23, 1999, the Companies filed with the SEC their Annual Report on Form 20-F for the year ended December 31, 1998 (the "1998 20-F"), signed by Defendant Maarten van den Bergh for Royal Dutch, and by Defendant Mark Moody-Stuart for Shell Transport. Under the headings "Description of Activities/Exploration and Production," the 1998 20-F gives the following summary information for proved developed and undeveloped reserves (at year end) for 1996, 1997, and 1998:

PROVED DEVELOPED AND UNDEVELOPED RESERVES (at year end)			
			Million barrels
	1998	1997	1996
Crude oil and natural gas liquids			
Group companies	8,779	8,354	9,049
Group share of associated companies	1,252	1,327	386
	10,031	9,681	9,435
			billion standard cubic feet
Natural gas			
Group companies	54,333	49,765	47,477
Group share of associated companies	6,129	6,366	5,550
	60,462	56,131	53,027

304. Under the heading "Exploration and Production," the 1998 20-F gives the following information concerning increases in total proved oil and gas reserves between 1997 and 1998:

Reserves

During 1998 the Group's total proved reserves for oil (including

> natural gas liquids) and natural gas increased from 19.4 to 20.5 billion barrels of oil equivalent. . . . The net additions to proved reserves more than replaced the 1998 production, with replacement ratios of some 140% for oil (compared with 130% in 1997) and some 250% for gas (compared with 210% in 1997). The additions to oil reserves arose mainly from revisions in existing fields in Nigeria, the UK and Oman, which were partially offset by reductions in Venezuela and the USA and by the disposition of Colombian interests. The additions to proved gas reserves result from increases and revisions in existing fields and from the acquisition of additional interests in gas fields in Malaysia, the Philippines, Bangladesh, Pakistan and Argentina.

305. In a section entitled "Supplementary Information – Oil and Gas," the 1998 20-F provides the following additional information about the Companies' reserves:

> Proved reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. ***The reserves reported exclude volumes attributable to oil and gas discoveries which are not at present considered proved. Such reserves will be included when technical, fiscal and other conditions allow them to be economically developed and produced.*** [Emphasis added.]

306. As Defendants knew or were reckless in not knowing, the statements in the previous three paragraphs – concerning the figures set forth for proved developed and undeveloped reserves (at year end), the figures for additions to proved oil and gas reserves and for replacement ratios, and the explanations for the increases, and the exclusion from reported reserves of volumes attributable to discoveries "which are not at present considered proved" – were materially false and misleading when made for the reasons given in ¶ 302, and the paragraphs cited therein.

307. Certain of the Companies' financial metrics are directly tied to their reported proved hydrocarbon reserves. Thus, when Defendants made the foregoing materially false and

misleading statements concerning those reserves (and related metrics, such as reserve replacement ratios), they also, as a consequence, made false and misleading financial statements. In the 1998 20-F, Defendants reported year-end cash flow provided by operating activities of $14.729 billion, which was overstated in an amount that cannot be determined from publicly available documents. Exploration costs were reported to be $1.603 billion, which were understated in an amount that cannot be determined from publicly available documents. Defendants reported net income for 1999 to be $350 million, which was overstated in an amount that cannot be determined from publicly available documents. (In their Annual Report on Form 20-F/A for the year ended December 31, 2002, Defendants admit that the Companies' "pre 2000" net income was overstated by $70 million (ignoring adjustments unrelated to reserves). Defendants do not allocate the $70 million overstatement in net income to specific years.)

308. Under the heading "Other Matters," the 1998 20-F also provides the following information, inter alia, concerning the Companies' internal controls:

> Internal controls
>
> The Royal Dutch/Shell Group of Companies has a number of control instruments that are considered to provide a reasonable balance between a comprehensive internal control structure and the need for a strong entrepreneurial decentralized culture. The primary control mechanisms are self-appraisal processes in combination with strict accountability for results. These mechanisms are underpinned by a number of checks and balances including mandatory policies, procedures (within the framework of the Royal Dutch/Shell Group of Companies' *Statement of General Business Principles*), and appraisals and reviews.

309. As Defendants knew or were reckless in not knowing, the statements in the previous paragraph concerning the existence of effective "control mechanisms" and "checks and balances" were materially false and misleading when made because Defendants failed to comply with SEC guidelines for the reporting of proved reserves (see ¶¶ 6, 11-12, 127-42, 147, 149-84,

296, 489-91); engaged in the "management" of proved reserves and the concealment thereof (see ¶¶ 14, 164-65); utilized only a single Group Reserves Auditor worldwide, who worked part-time, lacked the authority to require operating unit compliance, and reported to the very people he audited (see ¶¶ 148, 288-91); relaxed the Companies' accounting guidelines to enhance their bookings of proved reserves (see ¶¶ 127-42); and disregarded evidence of the improper classification of proved reserves (see ¶¶ 149-84). See generally ¶¶ 284-94.

310. The 1998 20-F attaches KPMG's "Report of Independent Accountants" for Royal Dutch relating to specified financial statements. The KPMG Report, which is dated March 11, 1999, states in relevant part:

> We have audited the Financial Statements of Royal Dutch Petroleum Company for the years 1998, 1997 and 1996 appearing on pages R-2 to R-6. The preparation of these Financial Statements is the responsibility of the Board of Management. Our responsibility is to express an opinion on the Financial Statements based on our audits.
>
> ***We conducted our audits in accordance with generally accepted auditing standards in the United States of America***. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Financial Statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the Financial Statements. An audit also includes assessing the accounting principles used and significant estimates made by the Board of Management in the preparation of the Financial Statements, as well as evaluating the overall Financial Statement presentation. ***We believe that our audits provide a reasonable basis for our opinion.***
>
> ***In our opinion, the Financial Statements referred to above present fairly, in all material respects, the financial position of Royal Dutch Petroleum Company at December 31, 1998 and 1997, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1998*** in accordance with the accounting policies described on page R-3. [Emphasis added.]

311. Similarly, the 1998 20-F attaches PwC's "Report of Independent Accountants" for Shell Transport relating to specified financial statements. The PwC Report, which is dated March 11, 1999, states in relevant part:

> We have audited the Financial Statements of The "Shell" Transport and Trading Company, Public Limited Company for the years 1998 and 1997 appearing on pages S-3 to S-8. The preparation of the Financial Statements is the responsibility of the Company's Directors. Our responsibility is to express an opinion on those Financial Statements based on our audits.
>
> ***We conducted our audits in accordance with generally accepted auditing standards in the United States***. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Financial Statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the Financial Statements. An audit also includes assessing the accounting principles used and significant estimates made by the Company's Directors in the preparation of the Financial Statements, as well as evaluating the overall Financial Statement presentation. ***We believe that our audits provide a reasonable basis for our opinion***.
>
> ***In our opinion, the Financial Statements referred to above present fairly, in all material respects, the financial position of The "Shell" Transport and Trading Company, Public Limited Company at December 31, 1998 and 1997, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1998***, in conformity with the accounting principles described in Note 1 on page S-5. [Emphasis added.]

312. The 1998 20-F also attaches KPMG and PwC's "Report of Independent Accountants" for Royal Dutch and Shell Transport relating to specified financial statements. This Report, which is also dated March 11, 1999, states in relevant part:

> We have audited the Financial Statements appearing on pages G-2 to G-30 of the Royal/Dutch [sic] Shell Group of Companies for the years 1998, 1997 and 1996. The preparation of Financial Statements is the responsibility of management. Our responsibility is to express an opinion on Financial Statements based on our audits.