Matthew J. Foehr
Vice President and
Comptroller

Chevron Corporation
Comptroller's Department
6001 Bollinger Canyon Rd
San Ramon, CA 94583-2324

April 13, 2010

BY ELECTRONIC TRANSMISSION

Mr. H. Roger Schwall
Assistant Director
Mail Stop 7010
Division of Corporation Finance
Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549-7010

Re: Chevron Corporation
Form 10-K for Fiscal Year Ended December 31, 2009 Filed February 25, 2010

File No. 001-00368

Dear Mr. Schwall:

In your letter dated March 31, 2010, you provided comments of the staff of the Division of Corporation Finance of the Securities and Exchange Commission on the Chevron Corporation ("Chevron" or "the company") 2009 Form 10-K. These comments and the company's responses are set forth below.

If you wish to discuss or have any questions related to the information herein, please contact Mr. Al Ziarnik, Assistant Comptroller, by telephone at (925) 842-5031 or by e-mail at apzi@chevron.com.

General

Comment 1

Please correct your commission file number on the cover of your periodic and current filings to read 001-00368.

Response:

We will include the file number in this format on future periodic and current filings.

Management's Discussion and Analysis, page FS-2

Comment 2

You state on page FS-9 that exploration expenses in 2009 increased from 2008. In addition, you state on page FS-12 that capital and exploratory expenditures were $22.2 billion in 2009 and $22.8 billion in

2008. We note your disclosure in Table I on page FS-64, however, that costs incurred in exploration, property acquisitions and development decreased from $18.2 billion in 2008 to $13.8 billion in 2009. With a view towards disclosure, please discuss the reasons for the decrease in costs incurred in exploration, property acquisitions and development. Please also discuss how this cost relates to the exploration expenses discussed on page FS-9 and capital and exploratory expenditures discussed on page FS-12.

Response:

Because Chevron's Upstream Capital and Exploratory Expenditures (C&E) include expenditures for activities other than those permitted to be reported in Table I — *Costs Incurred in Exploration, Property Acquisitions and Development (Costs Incurred*) of the Supplemental Information on Oil and Gas Producing Activities, the amounts reported for C&E differ from *Costs Incurred*, as noted in your comment. These additional expenditures include those for liquefied-natural-gas (LNG) operations, crude-oil and natural-gas transportation and support facilities. In addition, *Costs Incurred* reflect additions to property, plant and equipment, which consist of cash expenditures reported as C&E, additions resulting from accrued liabilities that will be paid in future periods, and amounts reported as exploration expense.

Costs Incurred reported for 2008 included the accrual of obligations related to Upstream operating agreements outside the United States, which were paid and reported as C&E during 2009. Discussions of the accounting effects of these transactions are contained in *Note 4 Information Relating to the Consolidated Statement of Cash Flows* on page FS-35 and in the MD&A discussion of *Capital and Exploratory Expenditures* on Page FS-12.

Supplementally, we provide the following reconciliation between reported amounts for *Costs Incurred* and C&E. Table I reported *Costs Incurred* of $13,783 million for 2009 and $18,232 million for 2008, a decrease of approximately $4.4 billion. The primary factors in the decline include:

- A decrease of $2.4 billion reflecting absence of the 2008 accruals for recognition of obligations related to operating agreements outside the United States.
- A decline of $1.5 billion in development costs in the United States, primarily as a result of a decrease in drilling activity in 2009.
- The net of all other effects was a decline of $0.5 billion.

As reported in the Capital and Exploratory Expenditures table on page FS-12, total Upstream expenditures in 2009 were comparable with 2008. The major offsetting changes included:

- An increase of $2.4 billion related to the payment of obligations accrued in 2008 related to operating agreements outside the United States.
- An increase of $1.0 billion related to LNG projects, primarily in Angola and Australia.
- A net decline of $3.3 billion, primarily reflecting a lower level of expenditures for major projects and a decrease in U.S. drilling activities. The change in the level of expenditures from year to year is affected by the amount of expenditures for major projects in the higher spending stages of development relative to those in lower spending stages. The projects with a decrease in C&E

expenditures in 2009 compared with 2008 include Agbami in Nigeria; Frade in Brazil; Tombua- Landana, Lucapa, Takula and other projects in Angola; Moho-Bilondo in the Republic of the Congo; the SGI/SGP project for the equity affiliate, Tengizchevroil, in Kazakhstan; and Blind Faith and Tahiti in the United States. Partially offsetting these decreases were projects with higher expenditures. These include the Usan development in Nigeria; the Platong Gas Project in Thailand; and the Nemba Field, the Malongo Terminal Oil Export Project and Block 0 exploration program in Angola.

As discussed on page FS-9, exploration expenses increased by $173 million due to higher well write-offs in the United States.

In future filings, we propose to more fully explain the relationship and clarify the differences between reported amounts for *Costs Incurred*, C&E and exploration expense, if material.

Comment 3

We note your disclosure on page FS-20 and FS-11. With a view towards disclosure, please explain in better detail the reason for the increase in contributions to employee pension plans of $1.7 billion in 2009 as compared to $800 million in 2008 and $300 million in 2007, as discussed on page FS-11.

Response:

In addition to the page references noted in the staff's comment, we have discussed pension plan funding in MD&A on page FS-12 and in Note 21 on page FS-57. As noted, pension plan funding decisions are based on the plan's current funded status, investment returns, cash availability, and other factors. The market downturn in 2008 reduced the market value of trust assets for the company's plans. Despite no legal requirement to do so, as a matter of business judgment, Chevron decided to contribute approximately $800 million to the global pension plans in 2008, and another $1.7 billion in 2009. We intend to continue to provide these disclosures in future filings.

Engineering Comments

Supplemental Information on Oil and Gas Producing Activities, page FS-69

Reserve Quantity Information, page FS-69

Comment 4

Revise your disclosure to clarify, if true, that the chairman of the Reserves Advisory Committee is the technical person primarily responsible for overseeing the preparation of your reserves estimates. Additionally, expand the discussion of his qualifications to describe, in reasonable detail, the specific areas or activities he has worked in during his 30 years in the oil and gas industry and how that experience qualifies him for his role as the technical person primarily responsible for overseeing the preparation of your reserves estimates.

Response:

The Reserves Advisory Committee (RAC) is the governance body that oversees the preparation of the company's reserves estimates. The RAC, led by the RAC chairman, establishes the policies and processes used within the operating units to estimate reserves. The chairman is not the individual technical person responsible for overseeing the reserve estimates. This oversight responsibility and accountability lies with the RAC as a whole. The full responsibilities of the RAC are described on page FS-69 of the 2009 Form 10-K.

The corporate reserves manager, who acts as chairman of the RAC, has more than 30 years experience in the oil and gas industry and a Master of Science in Petroleum Engineering degree from Stanford University. His experience includes 14 years of managing oil and gas reserves processes. He is the acting chairman of the Society of Petroleum Engineers Oil and Gas Reserves Committee, currently serves on the United Nations Expert Group on Resources Classification and is an active member of the Society of Petroleum Evaluation Engineers. He is also a past member of the Joint Committee on Reserves Evaluator Training and the California Conservation Committee.

The members of the RAC are degreed professionals, each with over 15 years experience in various aspects of reserves estimation relating to reservoir engineering, petroleum engineering or earth science, and receive annual training on the preparation of reserves estimates.

Based on the above, we believe the RAC chairman and RAC members are well-qualified to perform their responsibilities. In future Form 10-K filings, we will expand the commentary about the roles and qualifications of the RAC chairman and RAC members to reflect the details noted above.

Comment 5

We note in the geographic area called "Other" you include reserves from countries such as Brazil, Norway, Australia and Canada. These countries, however, are all in different continents. Explain to us your basis for this presentation. In this regard, note that Items 1201(d) and 1202(a)(2) of Regulation S-K do not contemplate reporting reserves by groups of countries that are in more than one continent. Based on that guidance, it appears that you should disclose reserves in the U.S. as it contains over 15% of your total reserves and then in the continents of North America, South America, Europe, Africa, Asia and Australia.

Response:

The geographical presentation of the reserves estimates and production was based on the guidelines presented in Items 1201(d) and 1202(a)(2), including the definition of the term "geographic area". While we acknowledge that the rules do not explicitly allow for aggregation of countries on different continents, we believe the geographic areas we used are consistent with the rule's directive to present the information as "appropriate for meaningful disclosure" under the company's particular circumstances. Individual countries, initially, and continents, secondarily, were disaggregated if reserves were equal to or greater than 15 percent of the company's total proved reserves. The United States was disclosed as a separate country because its reserves exceeded 15 percent of the company's total proved reserves. Similarly, Africa and Asia were reported as separate continents because their reserves exceeded 15 percent of the total proved reserves. We reported the remaining countries of North America, South America, Europe and Australia, which were not currently material on an individual country basis, or in the aggregate on a continent basis, as Other.

Supplementally, as a percentage of the company's total oil-equivalent reserves at December 31, 2009, Australia represented 10 percent, South America (including equity affiliates) represented 7 percent, Canada represented 4 percent (essentially all of which is disclosed separately as synthetic oil) and Europe represented 2 percent. Since none of these countries or continental areas met the materiality threshold, their reserves were aggregated and reported as Other.

The company believes the geographic reporting provided for year-end 2009 to be appropriate in current circumstances and in compliance with the rules. We review annually the geographic areas to be disclosed when preparing the Form 10-K for appropriate and meaningful disclosure. These geographic areas may be modified in the future as business conditions and the relative geographic breakdowns of reserves change.

Comment 6

Although you provided the amount of capital spent to convert proved undeveloped reserves to proved developed reserves and the amount of total proved undeveloped reserves at December 31, 2009, you did not provide the amount of reserves actually converted to proved developed in 2009 or previous years other than in 2009 for TCO, an affiliated company. Please explain to us why you believe this disclosure complies with Item 1203(b) of Regulation S-K.

Response:

For 2009, a total of 554 million barrels of oil equivalent was transferred from proved undeveloped to proved developed. The most significant reclassifications were due to the sour gas injection project at Tengizchevroil in Kazakhstan; development drilling at Agbami in Nigeria and at several fields in Angola; improved well performance in Bangladesh; start-up of production at the Tahiti Field in the United States; and other activities in various countries around the world. In future filings, we will disclose the amount converted and expand the commentary to describe the material drivers for the reclassifications from proved undeveloped reserves to proved developed reserves.

Comment 7

It appears that in your consolidated and affiliated companies over 38% of your proved undeveloped reserves have been so classified for five years or longer. Please provide us with a detailed description of the nature, current status and planned future activities of the specific projects underlying these reserves. While we understand that certain projects, including those related to deepwater reserves, may take longer than five years, it is not clear that compression, contract and capacity restrictions are sufficient reasons for such lengthy delays. Refer to Question 131.03 in the Division of Corporation Finance Compliance and Disclosure Interpretations, which can be found at:

http://www.sec.gov/divisions/corpfin/guidance/oilandgas-interp.htm

Response:

We have reviewed and assessed the applicable guidance in Question 131.03 referenced in the staff's comment and believe we are in compliance with the requirements. The company is engaged in a number of large scale projects in remote locations and challenging operating environments. External physical factors associated with these complex developments often result in development plans that require more than five years to complete. All major projects continue to progress, and the company has an excellent historical record of completing developments of these types. The company's proved undeveloped reserves associated with approved major projects are not affected by internal factors such as shifting resources to develop properties with higher priority.

The company believes it is in the shareholders' best interest to optimize the development plans for large scale, complex projects such that investments are made only when they can be economically utilized. External physical factors, including compression, contract and operational capacity constraints, and other variables, such as local demand for natural gas in areas outside the United States, affect optimal project development. Timing for the installation of compression is a special case in which the equipment is routinely installed at the point of depletion to maintain contractual rates; premature investment may defer or omit allocations of limited resources to additional economically attractive projects. In natural gas and liquefied natural gas developments, sales contracts exist with a prescribed delivery rate and the development of facilities may be scheduled to meet the contractual obligation. Similarly, in remote or adverse operating areas where infrastructure constitutes the majority of investment, field development is optimized around capacity constraints. Typical examples include deepwater developments with rig limitations, slot limitations, and/or facility limitations. In situations where an offshore platform can only accommodate one rig, the drilling plan progresses accordingly. In situations where facilities, plants, and/or pipelines constrain offtake rates, the project development is optimized around the governing capacity constraint. In these situations, if a project were terminated before completion, for whatever reason, a significant portion of the previously invested capital in the infrastructure would be lost. In future filings, we propose to provide additional explanation regarding these external factors in the discussion of reserves in Item 1, which is on page 6 of the 2009 Form 10-K.

At year-end 2009, the company held approximately 1.7 billion barrels of proved undeveloped reserves that have remained undeveloped for five years or more. The majority of these reserves are in locations where the company has a proven track record of developing major projects. For future filings, we will continue to evaluate the amount of detail we disclose to explain the nature, status and planned future activities associated with major projects with proved undeveloped reserves.

Supplementally, at year-end 2009, the major development projects that constitute a significant portion of the proved undeveloped oil-equivalent reserves that have remained undeveloped for five or more years include:

- Tengizchevroil, an equity affiliate in Kazakhstan, which accounts for approximately 800 million barrels. Field production is constrained by plant capacity limitations. The recent installation of the world’s largest sour gas processing and gas re-injection facilities converted reserves to proved developed. Further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion.

- Petropiar, an equity affiliate which operates the Hamaca Field’s synthetic heavy oil upgrading operation in Venezuela, accounts for about 150 million barrels of proved undeveloped reserves. Additional rigs are anticipated in 2010 to support further drilling of development wells to optimize utilization of upgrader capacity.

- In Africa, approximately 400 million barrels is related to deepwater and natural-gas developments in Nigeria and Angola. Major Nigerian deepwater development projects include Agbami (started production in 2008 with development continuing to maintain full utilization of infrastructure capacity) and Usan (currently under development). Also in Nigeria, various fields and infrastructure associated with the Escravos Gas Projects are currently under development (see responses to comments 11 and 12). In Angola, the Tombua-Landana deepwater project became operational in 2009, and development drilling is continuing to bring this field to maximum production.

- The Asia region held approximately 100 million barrels, primarily related to compression and contractual constraints in the Malampaya Field (Philippines) and infrastructure limits at the Duri Field (Indonesia). The timing of compression installation coincides with natural field decline and/or to meet contractual requirements. Ongoing development is scheduled to maintain production within the infrastructure constraints.

- In Australia, approximately 100 million barrels are classified as undeveloped due to compression limitations at the North West Shelf Venture. A project to improve compression is under construction and is expected to start up in 2013.

Comment 8

We note that the production figures in the reserve tables are identical to the production figures by country and continent on page five and include volumes of natural gas consumed in operations. However, we cannot find where you have disclosed sales volumes which should include only marketable production of natural gas on an "as sold" basis. See Instruction 2 to Item 1204.

Response:

The "as sold" basis of natural gas can be calculated by reducing the total production by the amounts disclosed in footnote 5 of the "Net Production of Crude Oil and Natural Gas Liquids and Natural Gas" table on page 5 that discloses the amounts of natural gas consumed in operations. The production amounts in the reserves tables and on page 5 include natural gas consumed in operations, thereby allowing the reader to reconcile the production between the two tables.

In future filings, we propose to include a footnote to the reserve table and the table on page 5 that discloses the total "as sold" amount of natural gas in each period.

Comment 9

You state that you added over 4.2 TCF of natural gas reserves in the Gorgon area of Australia. Please disclose if you used any alternative methods and technologies instead of production flow tests in determining material amounts of proved reserves that you added in 2009 and why those methods or technologies are considered reliable in the geological environment that they were used in. Also tell us how many of the added reserves were determined by these alternative methods and technologies.

In addition, tell us if you used any alternate technologies other than open-hole logs to determine gas-oil or oil-water contacts in determining material amounts of proved reserves that you added in 2009. If so, please tell us the amount of reserves added and why those methods or technologies are considered reliable in the geological environment that they were used.

Response:

Within the Greater Gorgon Area, specifically the Gorgon, Io and Jansz fields, alternative methods or technologies have not been used to add material volumes of proved reserves in excess of previously accepted evaluation techniques or technologies. In addition to production flow tests conducted in all three fields, methods used in the estimation of proved reserves include analogs, logs, cores, and 3-D seismic structural information validated by well control. Additionally, contact interpretations were based on logged well penetrations and were not based on alternative technologies.

Supplementally, with respect to the global use of alternative technologies, the company's 2009 proved reserves estimates included only limited application of pressure gradient data for two fields, resulting in additions of less than 20 million barrels of oil-equivalent. These additions were determined not to be material.

Comment 10

Explain to us how you considered disclosing the Canadian and Venezuelan synthetic oil reserves as a separate line item in the reserve reconciliation table rather than a revision of previously classified proved reserves since they have never been recognized as proved oil reserves in the past.

Response:

We considered whether to report the transition effects related to the Modernization of Oil and Gas Reporting as a separate line item, but concluded that it was clearer for the users to report these effects as revisions. We also believe that the categorization of these effects as revisions better complies with the captions prescribed by the rules.

To comply with the new rules, the transition effects associated with the Canadian and Venezuelan synthetic oil reserves were identified in separate columns on Table V on page FS-72, and footnotes 2 and 3 were added to Table V to provide further clarity. At the end of 2008, the company did not include any reserves associated with the Athabasca Oil Sands Project (AOSP) in Canada. Under the new rules, synthetic crude oil was introduced as a new category in Table V. Since the new rules were effective January 1, 2010, synthetic-oil reserves associated with the AOSP were reported as a revision for year-end 2009. Crude-oil reserves associated with the Hamaca heavy oil project at the company's equity affiliate in Venezuela were already recognized at year-end 2008 as the heavy oil was produced using in-situ techniques and was not mined. Under the new rules, these heavy oil reserves are now considered synthetic oil. As a result, the company recognized a negative crude-oil revision and a corresponding positive synthetic oil revision at year-end 2009. These revisions were also described in the explanatory text following Table V.

Comment 11

We note that your African gas reserves carry a 72 year reserve life and that apparently the majority of the gas production is only gas consumed in operations. Separately, we note that in 1999 you had booked 326 BCF of proved gas reserves and then in the next six years you added 2.4 TCF of proved gas reserves by way of positive revisions. During this period, it appears that you produced 152 BCF of gas for consumption in your operations. Explain to us how you are able to support the positive revisions in your reserve estimates in light of the relatively low levels of production over the relevant time period.

Response:

The company's natural gas reserve quantities are determined by combining estimates of future natural gas sales and future natural gas volumes to be used in operations. At year-end 2009, 31 percent of the consolidated companies' proved natural gas reserves in Africa were attributable to gas to be used in operations. The most significant parts of the natural gas reserves are associated with the sequential stages of the Escravos Gas Project (EGP) development, which are designed to achieve capabilities to supply natural gas under long-term contractual commitments. Specifically, EGP stage 1 supplies gas to the Nigerian Gas Company (NGC) for domestic use in Nigeria; EGP stage 2 supplies additional gas to the Nigerian domestic market, plus sales to customers in Benin, Ghana and Togo via the West African Gas Pipeline (WAGP); and EGP stage 3A is designed to supply gas to the Escravos gas-to-liquid (EGTL) facility for conversion to liquid fuel for the export market and domestic use in Nigeria. Deliveries to NGC were impacted by civil unrest beginning in 2003, and investments are underway to restore lost production capacity. Deliveries to WAGP were temporarily reduced during 2009 due to Nigerian domestic market requirements and vandalism to a third-party pipeline. All of these projects are discussed on pages 13, 14, 25 and 27 of the 2009 Form 10-K.

The positive reserve revisions that were noted in your comment are supported by the investment decisions for the sequential development of EGP and to supply various natural gas sales contracts. The seeming disparity of reserve life the staff noted is a reflection of the fact that the current gas utilization level as fuel in the African field operations is relatively low compared with the substantially higher natural gas production level that will be achieved when the various stages of EGP come on line to supply the natural gas sales routes and contracts discussed above. When the various EGP project stages and EGTL begin and then ramp up production, which are expected to occur in 2010 through 2012, the reserve life for the company's Africa natural gas will adjust itself to a lower figure.

Comment 12

We note that you did not take an investment decision on the Escravos Gas Project until 2005, yet you had classified almost 2 TCF of gas as proved by 2001 and almost 3 TCF by the end of 2004. Please explain the basis of those classifications at those times.

Response:

The natural gas reserves that were quoted in your comments are associated with all of the company's African fields. Nigeria represented 1.9 TCF and 2.6 TCF at the end of 2001 and 2004, respectively. The balance was associated with fuel gas expected to be used in the other African countries' operations.

The investment decision in 2005 noted in your comment is associated with EGP stage 3A. The investment decisions for the earlier stages of EGP were made for EGP stage 1 in 1995 and for EGP stage 2 in 1997. With the completion of EGP stage 2 in 2000, additional natural gas reserves were reported in 2001 consistent with the volumes under contract with NGC and fuel to be used in existing operations. Additional proved natural gas reserves were reported in 2004 and their classifications were supported by the final investment decisions for the WAGP and EGTL projects. These natural gas projects are either in execution stage or they are currently operational.

* * *

As also requested in your letter of March 31, 2010, we acknowledge the following:

- The company is responsible for the adequacy and accuracy of all disclosure in its filings.
- Staff comments or changes to disclosure in response to staff comments do not foreclose the Commission from taking any action with respect to the filing.
- The company may not assert staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

Very truly yours,

/s/ Matthew J. Foehr

cc: Mr. Terry M. Kee (Pillsbury Winthrop Shaw Pittman)