your own model and results. The economic viability and relief justification report must contain the following items for an oil and gas lease.

(a) Economic assumptions we provide which include:
   (1) Starting oil and gas prices;
   (2) Real price growth;
   (3) Real cost growth or decline rate, if any;
   (4) Base year;
   (5) Range of discount rates; and
   (6) Tax rate (for use in determining after-tax sunk costs).

(b) Analysis of projected cash flow (from the date of the application using annual totals and constant dollar values) which shows:
   (1) Oil and gas production;
   (2) Total revenues;
   (3) Capital expenditures;
   (4) Operating costs;
   (5) Transportation costs; and
   (6) Before-tax net cash flow without royalties, overrides, sunk costs, and ineligible costs.

(c) Discounted values which include:
   (1) Discount rate used (selected from within the range we specify).
   (2) Before-tax net present value without royalties, overrides, sunk costs, and ineligible costs.

(d) Demonstrations that:
   (1) All costs, gross production, and scheduling are consistent with the data in the G&G, engineering, production, and cost reports (§§203.86 through 203.89) and
   (2) The development and production scenarios provided in the various reports are consistent with each other and with the proposed development system. You can use up to three scenarios (conservative, most likely, and optimistic), but you must link each to a specific range on the distribution of resources from the RSVP Resource Module.

§ 203.86 What is in a G&G report?

This report supports the reserve and resource estimates used in the economic evaluation and must contain each of the following elements.

(a) Seismic data which includes:
   (1) Non-interpreted 2D/3D survey lines reflecting any available state-of-the-art processing technique in a format readable by BSEE and specified by the deep water royalty relief guidelines;

(b) Interpreted 2D/3D seismic survey lines reflecting any available state-of-the-art processing technique identifying all known and prospective pay horizons, wells, and fault cuts;

(c) Digital velocity surveys in the format of the GOM region’s letter to lessees of 10/1/90;

(d) Plat map of “shot points;” and

(e) “Time slices” of potential horizons.

(b) Well data which includes:
   (1) Hard copies of all well logs in which—
      (i) The 1-inch electric log shows pay zones and pay counts and lithologic and paleo correlation markers at least every 500-feet,
      (ii) The 1-inch type log shows missing sections from other logs where faulting occurs,
      (iii) The 5-inch electric log shows pay zones and pay counts and labeled points used in establishing resistivity of the formation, 100 percent water saturated (R_w) and the resistivity of the undisturbed formation (R_t), and
      (iv) The 5-inch porosity logs show pay zones and pay counts and labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time;

   (2) Digital copies of all well logs spudded before December 1, 1995;

   (3) Core data, if available;

   (4) Well correlation sections;

   (5) Pressure data;

   (6) Production test results;

   (7) Pressure-volume-temperature analysis, if available; and

   (8) A table listing the wells and completions, and indicating which sands and fault blocks will be targeted for completion or recompletion.

(c) Map interpretations which includes for each reservoir in the field:
   (1) Structure maps consisting of top and base of sand maps showing well and seismic shot point locations;

   (2) Isopach maps for net sand, net oil, net gas, all with well locations;

   (3) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and
§ 203.87 What is in an engineering report?

This report defines the development plan and capital requirements for the economic evaluation and must contain the following elements.

(a) A description of the development concept (e.g., tension leg platform, fixed platform, floater type, subsea tieback, etc.) which includes:

(1) Its size along with basic design specifications and drawings; and
(2) The construction schedule.

(b) An identification of planned wells which includes:

(1) The number;
(2) The type (platform, subsea, vertical, deviated, horizontal); and
(3) The well depth;

(4) The drilling schedule;

(c) A description of the production system equipment which includes:

(1) The production capacity for oil and gas and a description of limiting component(s);
(2) Any unusual problems (low gravity, paraffin, etc.);

(d) A discussion of any plans for multi-phase development which includes the conceptual basis for developing in phases and goals or milestones required for starting later phases.

(e) A set of development scenarios consisting of activity timing and scale associated with each of up to three production profiles (conservative, most likely, optimistic) provided in the production report for your field (§ 203.88).

Each development scenario and production profile must denote the likely events should the field size turn out to be within a range represented by one of the three segments of the field size distribution. If you send in fewer than...