July 26, 2007

VIA FEDERAL EXPRESS

Ronald M. Winfrey
U.S. Securities and Exchange Commission
100 F Street NE
Washington, DC 20549-7010

Re: Foothills Resources, Inc.
Amendment No. 4 to Registration Statement on Form SB-2
Filed May 30, 2007
File No. 333-137925

Dear Mr. Winfrey:

We are writing in response to the letter from Mr. H. Roger Schwall dated June 27, 2007, regarding Amendment No. 4 to the Registration Statement on Form SB-2 of Foothills Resources, Inc. (the "Company"), filed with the Securities and Exchange Commission on May 30, 2007, File Number 333-137925 (the "Registration Statement"). Mr. Schwall requested that we direct our response to comments 7(a), 7(b) and 7(c) in his letter to you. To facilitate your review of our response, we are including the comments in boldface type, followed by our response.

Engineering Comments

Description of Property, page 67

Oil and Gas Reserves, page 68

7. We have examined your third party petroleum engineering reserve report. Please furnish to us the following items in hard copy and electronic format:

(a) Narratives and engineering exhibits (e.g. maps, performance plots, volumetric calculations, well logs) to support your 14 California proved undeveloped locations.

RESPONSE: The requested information is enclosed with this letter in both hard copy, in the folder labeled "Comment 7(a)," and in electronic format on the CD-RW, in the folder labeled "Comment 7a."

Methodology

Please see the enclosed maps, logs, volumetrics calculations, and production performance maps as requested. We have also enclosed a strike cross section to illustrate roughly what the structure and pay sands look like.

Reservoir criteria for the Grizzly Bluff field were derived after an extensive evaluation of all tested, producing, or abandoned gas pay and water zones within the basin. The data set includes all 45

productive wells at the nearby Tompkins Hill field, and approximately 30 additional basin wells that tested Anderson or LRD equivalent sections.

The reserves criteria also incorporate published and internal field study reports on the Tompkins Hill gas field by Texaco field personnel. These studies, compiled in 1987, document average porosity, permeability and thickness values. These data confirm the use of sonic travel time and mud log criteria as an important component of defining pay.

Pay Determination

The pay criteria used here are further modified by petrographic analysis of full core and sidewall core data acquired in the Anderson sands in the Grizzly Bluff field. These data document compositional and mineralogical characteristics that cause the low contrast pay sands throughout the sections being analyzed.

Finally, the net pay criteria is constrained by tests of gas sands compared to tests including wet zones in several wells at Grizzly Bluff and at Tompkins Hill. These tests help confirm the sonic travel time criteria used as explained below.

The primary tools for counting net pay involve counts of SP through tested or productive zones. Production, log analysis, and core analysis document criteria that show the SP to be a relatively poor discriminator for the thin-bedded, low-contrast pay sections common in the Eel River Basin. Even with this knowledge, we use the SP counts for our current evaluation because it conforms to standard industry practices, the SP logs are available for over 95% of the wells in the basin, and the SP curve probably responds to the higher quality "net pay" in the basin. The sonic travel time is the most consistent indicator of gas pay throughout the basin. Most productive zones have sonic "shows" associated with them. A number of wells at Tompkins Hill field are perfed based solely on slow sonic "shows" in sections with virtually no other indications of pay or, in some cases, no evidence of reservoir development on other logs. Research indicates that sonic travel time of 110 msec/ft or slower are indicative of gas pay zones while zones with travel times between 100-110 msec/ft may flow gas or water depending on the mineralogy. Net pay criteria generally use a 110 msec/ft cut off for sonic pay. An additional criterion is provided by mud log shows. A correlation of sonic indications of pay with mud log gas shows is generally conclusive within the basin. Other logs add incremental confirmation of pay and help define additional parameters regarding porosity and thickness but are not primary gas pay indicators. Neutron, density, gamma ray, caliper, and resistivity data, although helpful in high grading pay vs. non-pay intervals, are not consistent indicators of pay or non-pay zones primarily because of mineralogy and thin-bedded pays common in the section.

The criteria for Anderson gas pay is fairly rigidly constrained to zones with sonic shows, mud log confirmation of gas and SP counts of net pay. The criteria used are conservative, defining low net pay counts in relatively thick intervals that are perfed and are producing gas without any water.

The LRD section has pay defined similarly using sonic shows and mud log confirmation, if available, and SP counts of net pay. The LRD was also analysed based on criteria of lower quality pay that is documented by sonic shows where no significant SP deflections occur. As previously mentioned, a number of wells producing at Tompkins Hill have perfed, productive gas pay where sonic travel time "shows" are the only indicators of gas or reservoir development. When analyzing the thick perfed or slotted liner production intervals in the Tompkins Hill and Grizzly Bluff fields, it becomes apparent that many feet of sonic indicated pay is open to production and has produced gas without significant associated water production.

Well Performance

The current analysis and reserves evaluation was predicated by new information derived from the Foothills Christiansen 3-15 (see accompanying performance chart) and Vicenus 1-3 wells drilled in 2006. Both wells are completed and hooked to the pipelines producing gas from Anderson and LRD sands.

Reservoir Parameters

The reserve analysis contained herein relied heavily on the Tompkins Hill Field developed by Texaco et al as an analog field. The sand development and reservoir conditions; for example porosity, water saturation, and pressure at Grizzly Bluff are remarkably similar to those at Tompkins Hill.

Container Volumetrics

To calculate reserves, individual maps are constructed for individual Anderson and Lower Rio Dell zones (see enclosed maps). The LRD10 map is used as a template for the PUD pay analyses for the entire LRD and Lower LRD (LLRD) sands (see enclosed LRD 6-13 and LRD 14-17 maps) because the structure is apparently consistent for the most part for the section. Net pay was defined using several criteria that primarily rely on SP and sonic indicators. Pay counts for SP criteria and sonic pay (not associated with SP net pay) for a number of the wells are shown in the following table.

The analysis was completed with SEC guidelines in mind. The basis of the proved drilling locations are the sustained through pipe production tests in the GB1,GB2, GB3, and the Chevron-Vicenus #1 wells. Each test recovered significant volumes of gas with little water and good reservoir pressure in the Lower Anderson, Lower Rio Del 6-17, and Lower Rio Del 18-25 sands. These production tests, most importantly the tests in the structurally low GB3, indicate that the PUD locations are above a possible gas water contact.

(b) Discussion of the procedures you used to determine that the Goose Creek Proved Developed Non-Producing wells are amenable to rehabilitation. Include work over prognoses and performance plots for the three largest PDNP wells as well as a schedule of the PDNP wells you have brought to production and the performance results to date.

RESPONSE: The requested information is enclosed with this letter in both hard copy, in the folder labeled "Comment 7(b)," and in electronic format on the CD-RW, in the folder labeled "Comment 7b."

Methodology

Developing the PDNP projects for Goose Creek was a cooperative project between a reservoir engineer, an operations engineer, and a development geologist. Each individual well was evaluated for remaining reserves and the mechanical condition of the well. Wellbore diagrams were developed for each of the shut in and producing wells at Goose Creek that showed the historical completion information. We developed cost estimates to recomplete into the zones that appeared to have been bypassed or undeveloped. Wells that had mechanical conditions that precluded the likelihood of successful completion of the work were not included as PDNPs. In several cases these reserves were moved to the PUD category and had to support the cost of new drilling to recover the reserves. Examples of this include the Ashbel Smith C #19 new drill where the sand is seen in the #18 , but the mechanical condition of the #18 precludes using it to the develop those reserves. Another example is

the A. Gaillard #49 new drill, where the reserves were logged in the A. Gaillard #45 but can't be recovered from that well with any degree of certainty.

Past PDNP Success and Present PDNP Candidates

The fact that these PDNP wells are amenable to rehabilitation has been shown by actual recompletion results in Goose Creek field, in which similar PDNP reserves have been brought to production. During the period of Foothills' ownership of the properties (since September 2006), 16 recompletions have been completed on the properties, with an 89% success rate (see enclosed tracking spreadsheet). The high success rate is due to the fact that most of the recompletions are mechanically simple uphole plugbacks. Per your request, we have enclosed data for the three largest-reserve PDNP wells. These wells are the Hog Island Fee #28, Simms Schilling #57, and Rucker Schilling #3. In addition to historical and projected performance plots, wellbore diagrams for the three wells are included, which show that the proposed work is of the simple type that has been so successful in the past. Another file is included showing prognoses/performance expectations for the Hog Island Fee #28 well. The 2nd well, the Simms Schilling #57, is currently producing strongly (18 BOPD), so we do not anticipate recompleting this well in the near future. Consequently, no detailed work procedure has yet been developed. The 3rd well, the Rucker Schilling #3, is being successfully recompleted as we write this and work should be finished in a day or so. This well stopped producing because it had become plugged with chemical residue, which has been successfully removed. The PDNP reserves assigned to this well were based on a resumption of the decline curve prior to the well going off production. We have provided prognoses/performance expectations for seven other PDNP wells as additional examples. Similarly to the three largest-reserve PDNP wells, most of these seven PDNP recompletions are simple uphole plugbacks (e.g., Simms Sweet 53, 54; Simms Schilling 55, 59), others involve only simple pump changes (e.g., Gaillard Peninsula Multi), and just a few involve moving downhole (Ashbel Smith 40, 50).

(c) Discussion of and support for the differences between the projected 2007 operating expense for proved developed producing properties on Table I-PDP and the historical production costs incurred. It appears that the Texas properties alone incurred $4,960 thousand in lease operating expense (page F-30) over the 18 months ending June 30, 2006 or $276,555/month. For 2005, the unit LOE is $12.67/BOE (=$3,358 thousand/265 MBOE). Your projected 2007 LOE for these same producing Texas properties plus the producing California properties is $2,332 thousand or $194,333/month even though the estimated production – 226 MBOE – is within 15% of the 2005 Texas production. The 2007 projected unit LOE is $10.32/BOE (=$2,332 thousand/226 MBOE). Please include spread sheet reconciliation between the incurred, historical LOE components and the projected LOE components you used.

RESPONSE: We have enclosed with this letter in both hard copy, in the folder labeled "Comment 7(c)," and in electronic format on the CD-RW, in the folder labeled "Comment 7c," a spreadsheet analyzing our historical and projected lease operating expenses for the Texas properties. The primary reason that projected operating expenses appear low in comparison to historical operating expenses is the impact of the non-recurring, extraordinary maintenance costs incurred by the previous owner of the properties. To enable the Company to prepare the Statements of Revenues and Direct Operating Expenses for the six months ended June 30, 2006 and 2005 and the years ended December 31, 2005 and 2004 included in the Registration Statement, the seller provided to us the historical production costs as reflected in its books and records. The seller indicated to us that these non-recurring items consisted primarily of expenses incurred to prepare the properties for sale.

In addition, the analysis in the comment above combines Texas and California PDP projections. Because our California production is 100% gas which commenced in September 2006, the production costs per BOE are much lower than the Texas production costs. Production from the Texas properties is primarily oil, and the properties have been in production for several decades.

Once these adjustments are taken into consideration, the projected Texas production costs per BOE are actually higher than historical costs, and the projected costs per month are about 7% lower than historical. The forecast production per day is 18% lower than the historical production, and we believe that a 7% reduction in costs per month is reasonable considering that a portion of the costs is variable with production.

* * *

We believe our responses contained herein adequately address your questions. Please feel free to call Michael Moustakis, our Vice President, Engineering, or Kirk Bosché, our Chief Financial Officer, at (661) 716-1320 if you require additional information or clarification of our responses.

Sincerely,

John L. Moran
President

cc: Michael Moustakis, Foothills Resources, Inc
Kirk Bosché, Foothills Resources, Inc.