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Practical application of geothermal resources management system based on SPE-PRMS concepts

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ABSTRACT

Why should we be concerned about geothermal reserves standards? Unlike the petroleum industry, the geothermal industry has no universally recognized set of guidelines, standards, or protocols to guide what are called ‘reserves’ or ‘resources’ in technical evaluations, financial statements and company annual reports. Consistency in reserves and resources classifications (wherein reserves are the commercially viable subset of resources), estimation methodologies, and the related disclosures is needed by geothermal asset teams, investors, regulators, and corporate management teams to benchmark geothermal opportunities and clearly communicate the differences using terms that are well defined and understood.

In our previous work (Gardner and Faulder 2024), we explored the applicability to the formulation of a classification framework for geothermal resources based on the SPE Petroleum Resources Management System (SPE-PRMS) and proposed an initial geothermal resources management system (GRMS). In this study, we will provide practical examples from certain geothermal projects and interpretations for applying the GRMS based on SPE-PRMS concepts.

This work aims to provide case studies to assist geothermal professionals in: 1) determining a geothermal *project*, 2) *classifying* resources based on commercial maturity, 3) quantifying and *categorizing* resources based on technical uncertainty, 4) and designating the development *status* of resources, all using the same framework. While we recognize that certain situations may arise requiring a departure from the PRMS as a guideline, the PRMS for hydrocarbons provides a good analogy and framework for the establishment of a GRMS and has an important advantage by being familiar and accepted by many energy stakeholders, including many new entrants into the geothermal market space.

The adoption and use of the GRMS are strategic to aid in the development and growth of clean and sustainable geothermal energy by promoting consistency, reliability, and transparency in estimates and reporting, which in turn help open the gates for greater geothermal investment.

1. INTRODUCTION

The lack of consistent, globally agreed-upon standards for assessing, classifying, and reporting geothermal resources is a major recognized challenge in the industry. For the geothermal industry to gain greater access to the investment capital needed to expand innovation, execute projects, and bring geothermal energy to more consumers, a widely accepted classification and disclosure standard is needed. Such a standard is critical in promoting consistent and transparent communication among stakeholders, which is important to understanding project uncertainties, comparing opportunities, transacting deals, approving projects, and so on. As proposed by Gardner and Faulder (2024), the SPE Petroleum Resources Management System, i.e., the SPE-PRMS, or simply PRMS (Society of Petroleum Engineers 2026) classification framework for hydrocarbons is a good model for a similar geothermal resources standard. Many investors, operators, and technical professionals in the geothermal energy industry have a background in hydrocarbons and are already familiar with the principles and application of the PRMS as an accepted global reserves and resources standard. Furthermore, there are many technical and commercial similarities between petroleum and geothermal energy that facilitate the utilization of PRMS guidelines in the formulation of a Geothermal Resources Management System, or GRMS. We refer the interested reader to the work by Gardner and Faulder for a more detailed description of the proposed standard and the definition of various important terms that are used throughout this work (Gardner and Faulder, 2024).

The GRMS, which again is based on the widely familiar and accepted principles of the PRMS, is a project-based classification system. Accordingly, once a geothermal development project has been identified and defined, its associated energy resources are then *classified* and *categorized* as shown in Figure 1 below. Classifications of resources are based on commercial maturity (y-axis), i.e., the stage of a project as it progresses from pre-discovery to product sales. The classes consist of prospective resources, contingent resources, and reserves. Categorization of resources refers to the technical uncertainty (x-axis) of estimated quantities within a given class, such as Proved, Probable, and Possible within the reserves class. As an example, geothermal resources that are commercially mature and highly certain are designated as Proved Reserves. Figure 2 is adapted herein from an original graphic contained in the SPE-PRMS and shows the various project maturity sub-classes and/or development statuses. These designations provide users with additional granularity to convey the maturity and/or development status of a given project. The authors present two different case studies in this work, referred to as Projects A and B, to help illustrate how the GRMS framework is applied. Figure 3 is a convenient flowchart that helps a user understand and navigate the class and category options described in Figures 1 and 2, as a project progresses and encounters various hurdles to reach the next level of maturity (Gardner and Faulder 2024). We encourage the reader to refer to Figures 1, 2, and 3 frequently while considering the explanations of Projects A and B, as presented in this work. Lastly, it is noted that the term commerciality used herein is in reference to a project's commercial maturity, as described above, which includes *all* factors required to achieve a successful producing project, e.g., discovery of a resource, a reasonable development plan, available funding and management's commitment to proceed with development, legal and regulatory requirements, social or environmental considerations, market access and demand, profitability, etc.

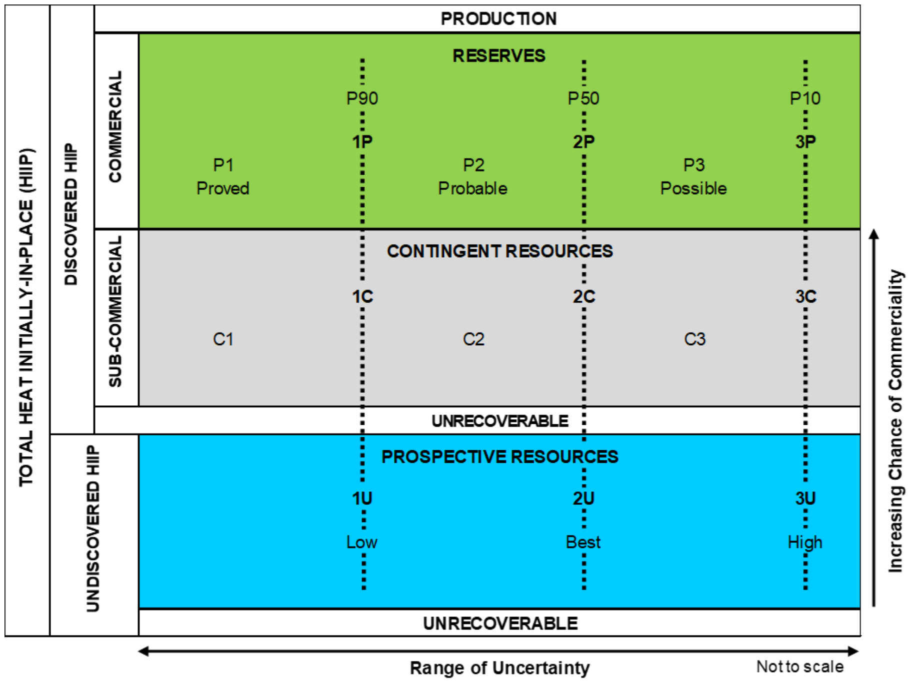


Figure 1: Geothermal resources classification framework (Gardner and Faulder 2024, as adapted from the SPE-PRMS).

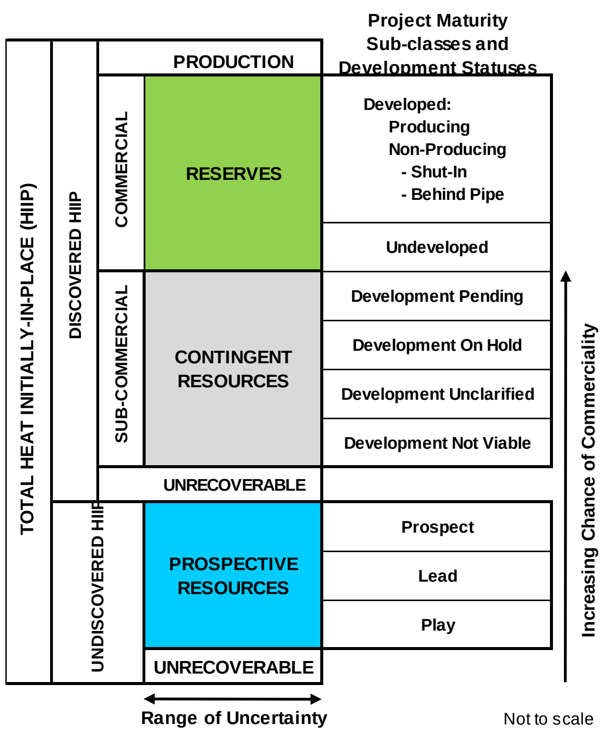


Figure 2: Project maturity sub-classes and development statuses (adapted from the SPE-PRMS, page 8).

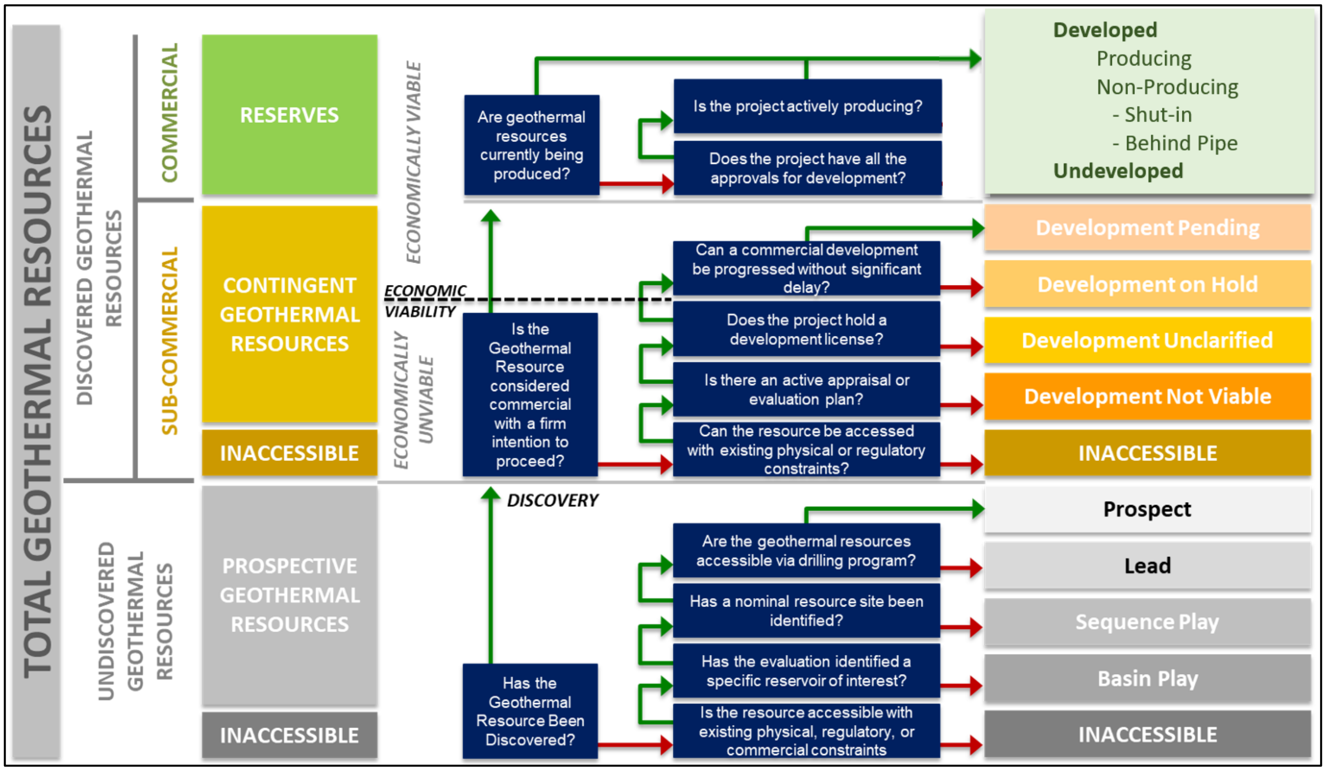


Figure 3: Flowchart for Assigning Project Sub-Classes (Gardner and Faulder 2024, originally adapted from the OGCI CO2 Storage Resource Catalogue Cycle 3 Report, page 16).

2. DETERMINATION OF A PROJECT

For any assessment of geothermal resources, it is first necessary to identify and define a development project to access and produce the resources. Regardless of the geothermal source in question, estimates of resources are inseparably tied to a contemplated development plan. Examples are given below.

Project A is a mature producing hydrothermal asset with additional undeveloped potential. Two separate geologic horizons will be exploited: 1) a legacy shallow zone that has been producing for 20+ years from multiple vertical wellbores, and 2) a deeper, hotter, and highly fractured zone that will be initially developed with a single pad of horizontal wells. Figure 4 is a map of the existing vertical wells along with the planned horizontal locations. The vertical wells will continue to be produced and/or refurbished to increase the deliverability of the existing power plant up to its nameplate capacity. Coincident with the horizontal drilling, the surface facilities will be expanded to handle the resulting additional production. It is important that surface facilities be included when defining a project's scope because factors such as the plant's generation capacity and efficiency, inlet and rejection temperatures, production and injection pressures, and others all affect the estimated quantities of recoverable and saleable geothermal resources. In the case of Project A, its available resources are therefore defined as the heat that is recoverable with the existing vertical wellbores plus the single pad of horizontal wells, while accounting for the plant design specifications. With the project's scope now defined, we are able to begin quantifying and classifying the associated resources.

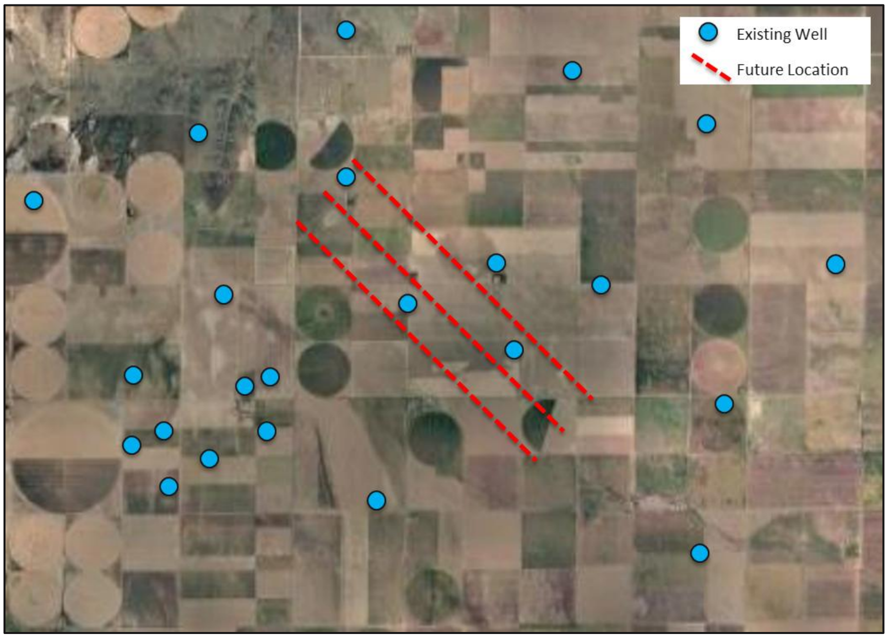


Figure 4: Development map for Project A (existing vertical and deviated wells in blue; planned horizontal locations in red).

Project B is an enhanced geothermal system (EGS) opportunity in the early stages of development. Recent regional geothermal potential analytics have indicated a favorable geological condition for EGS development in dry igneous rock with temperatures above 200°C at a depth of 2 km (Figure 5). The development plan includes a series of alternating horizontal production and injection wells, plus surface facilities designed to handle the anticipated flow rates during operations. The wells will be fracture stimulated to create interconnecting flow paths between the various horizontal wells, and the gross available geothermal resources associated with Project B are directly linked to the three-dimensional volume of rock that is contacted by the planned network of wells and hydraulic or induced fractures, i.e., the stimulated rock volume (SRV). Primary considerations in determining the SRV include the number, length, and spacing pattern of the horizontal wellbores as well as the geometry of the induced fractures. Accordingly, the SRV, or "drainage" volume, of the geothermal resources for Project B is defined by the intended development plan, as depicted in Figure 6. For the purposes of our discussion, we presume that the surface facilities will be right-sized to accommodate the quantity of planned wells along with their anticipated flow rates. To this point, two vertical appraisal and monitoring wells have been drilled, and one triplet unit of horizontal wells has been drilled and fracked. We also note that an extended flow test has been performed within the triplet unit, which is an important detail to keep in mind for later sections of this work.

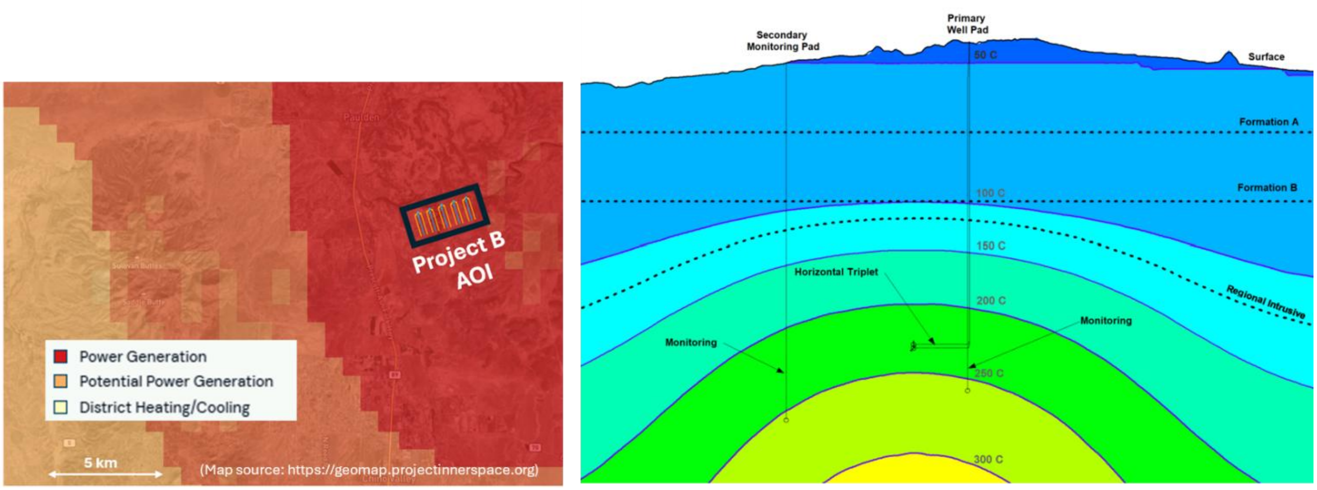


Figure 5: Project B hypothetical EGS field power generation favorability map (left) and temperature model cross-section with well trajectories of the current triplet unit and two monitoring wells (right)

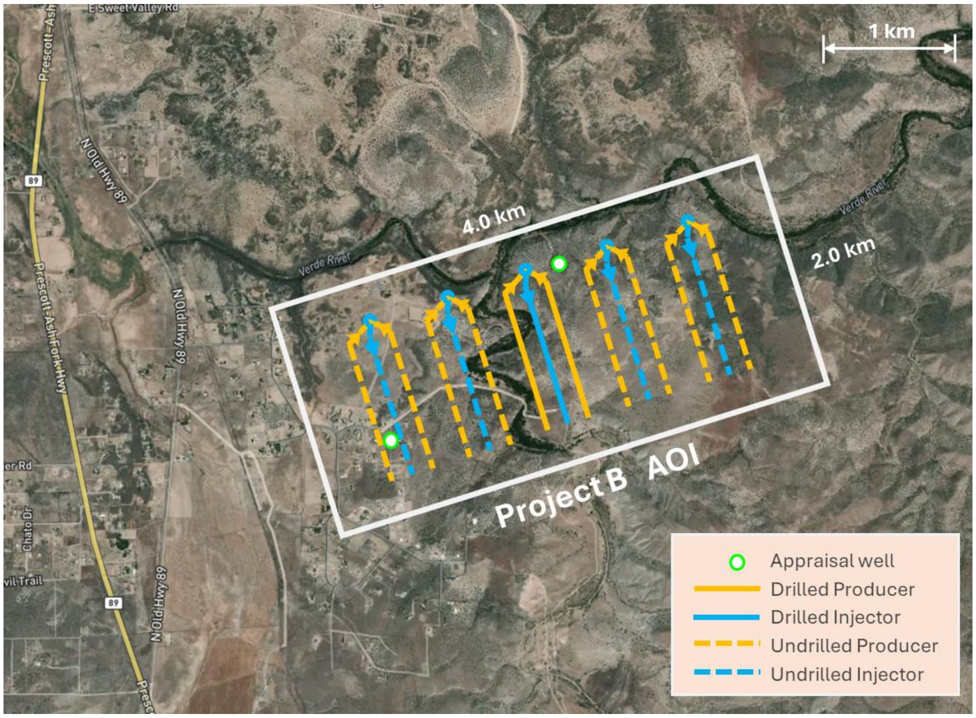


Figure 6: Hypothetical EGS field development map of Project B. To simplify the numerical model for reservoir simulation, the full-field development plan is modeled with repeating well triplets.

3. CLASSIFICATION OF RESOURCES

To begin our discussion regarding classification of resources, recall that different classes correspond to different levels of commercial maturity (refer to the y-axis in Figure 1). Undiscovered resources are designated as Prospective, and the key criteria to achieve discovery status are to demonstrate evidence of 1) temperature and 2) producibility. Once a discovery has been made by drilling a well, the resources mature into the Contingent class. Contingencies can include many factors, such as: formulating a reasonable development plan, obtaining capital funding and management's commitment to proceed with development, legal and regulatory requirements, social or environmental issues, market demand and securing access to a market, costs and prices, essentially anything that could impede a geothermal project from becoming a profitable operation. After all commercial hurdles have been met, the project matures into the *reserves* class.

In Project A, the criteria for discovery are satisfied by the numerous existing well penetrations, some of which penetrate both the shallow and deep zones of interest. These wellbores confirm both the subsurface temperature gradient as well as the producibility of both targeted formations. Although the shallower zone had been the most active horizon, there was sufficient production data from the deeper zone to estimate a range of expected production rates from new horizontal wellbores. Regarding the various commercial criteria, most requirements are fulfilled simply by the fact that the project is part of, or an extension of, an already sanctioned and active geothermal operation. Additional analysis was placed on establishing reliable market demand and access, obtaining capital funding for the new drilling, and of course building a cash flow model to show favorable project economics. With no commercial contingencies remaining, Project A qualifies for classification as reserves. The maturity sub-class for Project A will be addressed later in section 5.

In Project B, the discovery criterion for temperature was met by multiple vertical well penetrations in the vicinity, including two appraisal wells within the development area. These wells provided sufficient data to generate a high-confidence temperature contour map that shows a heat anomaly believed to be the result of crustal thinning and a shallow magma body (Figure 5). The mapped rock volume included the depth of interest within the leased acreage. Temperature gradients were further validated with the drilling of the first set of horizontal development wells. Additional planned horizontal wells will be drilled in the adjacent acreage. The discovery criterion for producibility is more complicated for Project B than for a conventional hydrothermal project, as it may be for other EGS opportunities. The demonstration of successful fluid flow and heat transport between injector-producer pairs is situationally specific, and may be satisfied through various means. Such means include a pilot program or flow test within the lease via a doublet or triplet system, an acceptable analogy from another EGS project, perhaps even pressure and/or microseismic data during fracture stimulation operations, or other data. Here, the development activities for Project B had matured to the point of performing an extended flow test within the initial triplet unit, which provided valuable data to further refine facilities designs, estimated flow rates and pressures, economic models, remaining drilling and completion designs, etc. Other commercial criteria had been fulfilled by obtaining all regulatory permits, including additional drilling permits, as well as obtaining power purchase agreements, capital funding, and the remaining construction services. As in the case of Project A, the geothermal resources for Project B also qualify to be classified as reserves.

4. QUANTIFICATION AND CATEGORIZATION OF RESOURCES

Within each resource class, the range of estimated quantities is divided into categories, with each category representing a higher or lower level of technical uncertainty. Together, the class and category convey the commercial maturity and the level of technical confidence for a given estimated quantity of resources, respectively. Referring to Figure 1, the reserves class is separated into proved (P1), probable (P2), and possible (P3) categories. Similarly, the contingent resources class is separated into C1, C2, and C3 categories that correspond to the same levels of technical uncertainty as P1, P2, and P3, with the only differences being any commercial contingencies. Prospective resources categories consist of low, best, and high estimates, which are inherently more generalized than the other classes due to their exploratory nature and typically limited data. The appropriate category for a given estimated quantity of resources primarily depends upon the quantity and quality of technical data at the time an estimate is made and the interpretation of those data. Accordingly, as an evaluator conducts his/her analysis, it is his/her responsibility to determine the range of estimated quantities *and* the corresponding level of uncertainty.

The reserves for Project A are associated with a shallow developed zone, along with a deeper zone that will be exploited with future horizontal drilling. Reserves for the shallow reservoir were estimated by historical performance, taking into account the facility constraints. Quantities of producing reserves from the existing active wells were estimated using their historical production trend. The operator plans to perform subsurface well remediation, as well as refurbishment of the existing surface facilities in order to restore the operations to their designed production levels. Hence, additional reserves were based on the incremental recoverable quantities resulting from the repairs. The total production rates were then projected at the maximum capacity of the facilities, since the shut-in wells will have spare deliverability once they are restored. Estimated decline rates were then applied based on different levels of technical uncertainty and categorized as proved, probable, and possible. Figure 7 is a stacked chart of the different wedges of production for the shallow zone, as well as the cumulative reserves quantities.

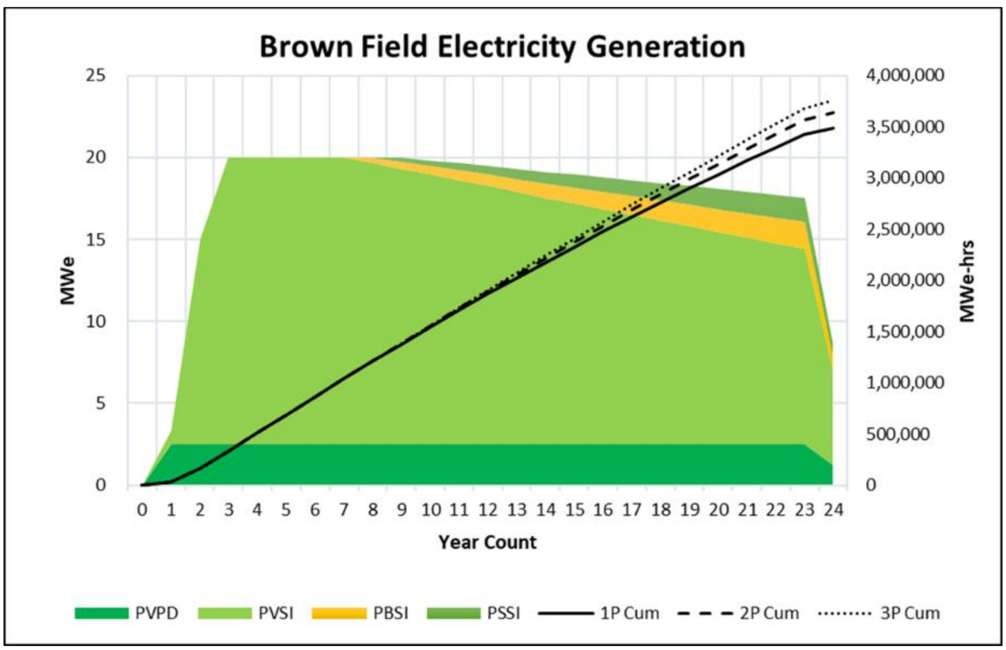


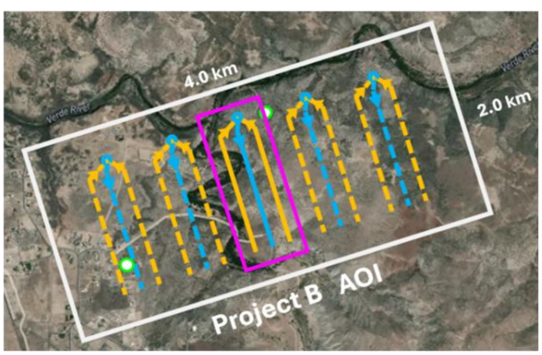
Figure 7: Estimated production profiles and cumulative quantities of reserves associated with the existing shallow wells, or "Brown Field" development, in Project A.

Additional reserves from the deeper field expansion at Project A were estimated using heat-initially-in-place (HIIP) calculations. Accordingly, temperatures from log data were used to generate temperature contour maps at various depths, and those contour maps were then used to determine an average temperature throughout the development area. Porosity, lithology, and brine composition were also determined from well log and production data. Specific heat and density properties for rock and brine were then derived from known correlations. Plant conversion efficiency and parasitic load factors were provided by the equipment manufacturer. Different drainage areas and thermal recovery factors were estimated at different levels of technical uncertainty, based on experience and judgement, and used to estimate quantities of 1P, 2P, and 3P reserves. As represented in Figure 1, cumulative quantities of reserves are categorized as 1P (proved), 2P (proved plus probable), and 3P (proved plus probable plus possible), whereas the corresponding incremental quantities are designated as proved (P1), probable (P2), and possible (P3). Table 1 summarizes the HIIP calculations along with the different reserves estimates for the future horizontal drilling at Project A. Although not shown, the reserves volumes were then projected over a 20-year period, which incorporated capacity limits of the facilities and estimated decline rates based on each different level of technical uncertainty.

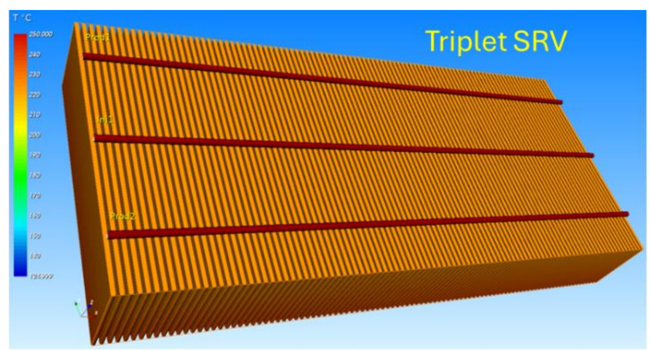
Table 1: A summary of the HIIP calculations and subsequent estimates of 1P, 2P, and 3P reserves associated with drilling the deeper zone and expanding the surface facilities, or the "Green Field" development activities, at Project A.

Category	Drainage Thickness (ft)	Drainage Area Dimensions	$HIIP_{available}$ (kJ)	RF_t	$HIIP_{recoverable}$ (MWh_t)	η_{eff}	Gross Electricity Generation (MWh_e)	Parasitic Load	Net Electricity Sales, Reserves (MWh_e)
1P	1000	5200'x15840'	8.77E+14	10%	24,361,111	24.85%	6,053,736	15%	5,145,676
2P	1000	8250'x15840'	1.301E+15	15%	54,208,333	24.85%	13,470,771	15%	11,450,155
3P	1000	11346'x15840'	1.790E+15	20%	99,444,444	24.85%	24,711,944	15%	21,005,153

Due to the very early performance history in the field, and limited analogy information from other operations, the reserves at Project B were estimated using a combined volumetric and numerical simulation approach. As mentioned in a previous section of this document, there were high quality data with regard to subsurface temperatures, porosity, and lithology. Also, power plant design specifications were supplied by the manufacturer to estimate production capacity, electrical conversion efficiency, and part of the parasitic load. Since Project B is an EGS project, water properties and their interaction with the reservoir rock are based on the supply water and results of the flow-test operations. Thus, some remaining key variables that contribute to the range of technical uncertainty for reserves were drainage area (i.e., SRV), flow impedance, and thermal recovery factor, all of which are influenced by well spacing, the fracture stimulation strategy, temperature decline, and water leak-off. From data collected during completion and flow test operations on the initial wells, the first triplet's SRV at three levels of uncertainty was assessed as shown in Figure 8. Three sector models were constructed, one for each estimated SRV, to simulate the heat recovery for a single triplet unit. The simulation results of the single triplet unit were then scaled up to approximate the full development plan (5 triplet units), assuming no fracture interactions between each triplet unit for simplicity.



	Project B Triplet SRV Volumetric Uncertainty		
Scenario	LOW	ML	HIGH
SRV	425x275x1350m	450x300x1500m	500x350x1500m
Area (Km2)	0.57	0.675	0.75
Thickness (m)	275	300	350
GRV (m3)	1.58E+08	2.03E+08	2.63E+08



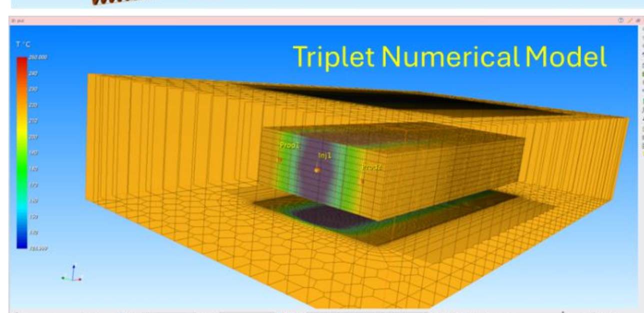


Figure 8: A triplet sector model for the EGS operation at Project B, which represents half of the SRV interpreted from 4D micro-seismic events with 100 fractures (top right). The grid in the numerical model for the SRV is surrounded by an unstimulated igneous body (bottom right).

By assuming uniform flow across 100 fractures that are evenly distributed along a 1500 m lateral, the simulation result indicated thermal breakthrough six years after the start of geofluid circulation, followed by a 4% annual thermal decline for the most likely (ML) case, as shown in Figure 9. The water circulation rate was held constant throughout the simulation, which resulted in a plant inlet temperature that started at 200°C and gradually declined to 160°C for the ML case at the end of the 15-year project life. Figure 10 shows the final reservoir temperature distribution after 15 years of heat extraction. Due to the uniform fracture spacing and uniform flow assumption in this example, the final temperature distribution is consistent across fractures except for the well heels and toes. Figure 11 gives the parameters used in calculating the HIIP for each of high, low, and most likely cases, and incorporates an electrical conversion efficiency and a parasitic load based on the facilities design. The production profiles and associated reserves were estimated from the simulation modeling of the three SRV cases with their rock and fluid parameters obtained from the monitoring wells and labs. We note that reserves are cumulative quantities of energy (megawatt-hours, or MWh), whereas the power production profile is the rate (megawatts electric, or MWe) at which the reserves are recovered.

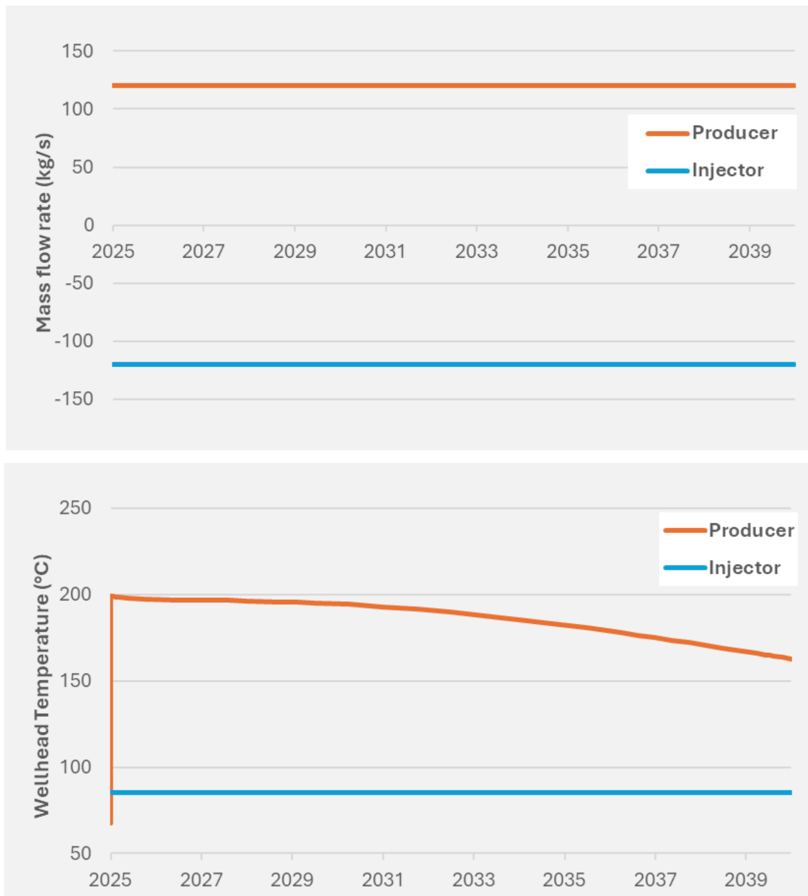


Figure 9: Triplet circulation rate (top) and surface temperatures (bottom) during the simulated 15-year project life at Project B for the most likely case.

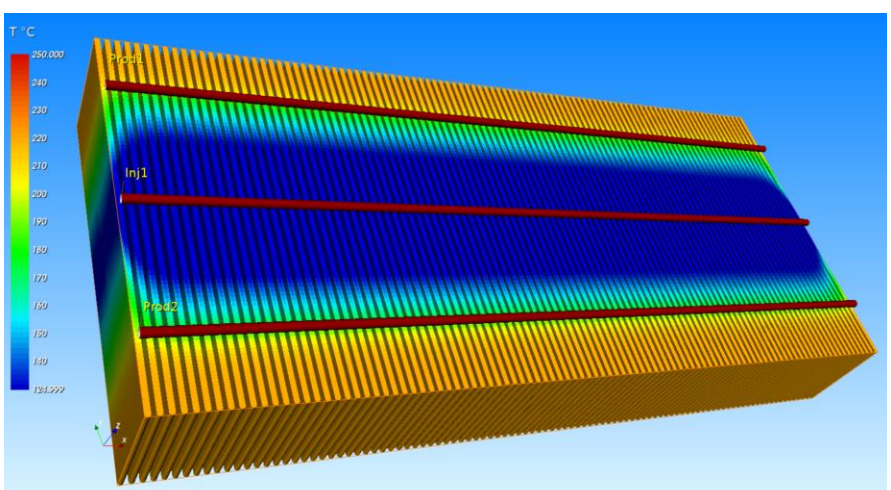


Figure 10: The final reservoir temperature distribution of the lower-half sector model for Project B after 15 years of heat extraction.

Project B Triplet SRV Volumetrics			
Scenario	LOW	ML	HIGH
SRV	425x275x1350m	450x300x1500m	500x350x1500m
Area (Km2)	0.57	0.675	0.75
Thickness (m)	275	300	350
GRV (m3)	**1.58E+08**	**2.03E+08**	**2.63E+08**
Rock Density (Kg/m3)	2700	2700	2700
Tres (°C)	230	230	230
Tinj (°C)	80	80	80
Heat Capacity (J/Kg-K)	1000	1000	1000
HIIP (MJ)	6.39E+10	8.20E+10	1.06E+11
15-year Gross Recoverable Heat (MJ)	2.12E+10	2.62E+10	2.84E+10
η_{eff}	20%	20%	20%
15-year Gross Electricity (MWh)	1.18E+06	1.46E+06	1.58E+06
Parasitic Load	20%	20%	20%
15-year Net Electricity (MWh)	**9.44E+05**	**1.16E+06**	**1.26E+06**
Levelized Net Power (MWe)	**7.19**	**8.86**	**9.62**

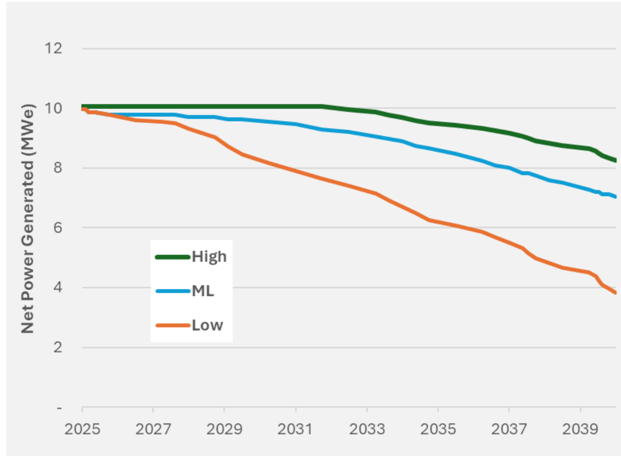


Figure 11: Input parameters for the HIIP and net electricity reserves (left) and the net power sales profiles (right) from the low, most-likely, and high cases for a single triplet unit.

As mentioned previously, the reserves and production profile for full-field development were estimated by scaling up the single triplet model to full-field five triplet units (Table 2), considering the project's operational maturity and for illustrative purposes. We note that the full-field gross rock volume (GRV) shown in Table 2 includes additional rock volumes between the individual triplet units, as they are spaced out across the development area. Based on the levels of uncertainty for the low, most likely, and high scenarios at Project B, the reserves associated with each scenario are categorized as 1P, 2P, and 3P, respectively. Figure 12 shows the production profile for each reserves category, along with the Minimum Contracted Quantity (MCQ) that is specified in the operator's Power Purchase Agreement (PPA). It is observed that the 1P production profile drops below the PPA MCQ after about 4 years. The 2P production profile is sufficient to fulfill the PPA MCQ for the full project life, but recall that it is less certain than the 1P case. As a result, there is a quantity of resources represented by the shaded wedge between the 1P profile and the PPA MCQ that can be categorized with higher technical certainty *by planning to drill make-up wells if/when the produced temperature and the corresponding power generation declines*. These make-up wells, as the operator's contingency plan, would be drilled within the field and beneath the first phase of drilled wells into deeper, hotter rock. The make-up wells qualify as high technical certainty since they are based on the same data set and criteria as the 1P reserves, except that they are contingent upon reservoir performance (i.e., the make-up wells are only needed if power generation declines as is predicted in the 1P case). Consequently, the resources from the make-up wells are classified as contingent and categorized as 1C. The contingency lies in the fact that the wells are not currently committed.

Table 2: A summary of the HIIP calculations, thermal recovery factors, and subsequent estimates of 1P, 2P, and 3P reserves at Project B for full-field development (i.e., five triplets).

Project B Full-Field Volumetrics			
Scenario	1P	2P	3P
GRV (m3)	**1.11E+09**	**1.35E+09**	**1.71E+09**
Rock Density (Kg/m3)	2700	2700	2700
Reservoir Mass (Kg)	3.00713E+12	3.645E+12	4.60688E+12
Tres (°C)	230	230	230
Tinj (°C)	80	80	80
Heat Capacity (J/Kg-K)	1000	1000	1000
HIIP (MJ)	4.51E+11	5.47E+11	6.91E+11
Technical RF* (%)	**26.0%**	**30.0%**	**32.0%**
15-year RF (%)	**23.5%**	**24.5%**	**20.6%**
15-year Gross Recoverable Heat (MJ)	1.06E+11	1.34E+11	1.42E+11
15-year Gross Recoverable Heat (MWh-th)	2.94E+07	3.72E+07	3.95E+07
η_{eff}	20%	20%	20%
15-year Gross Electricity (MWh)	5.89E+06	7.44E+06	7.91E+06
Parasitic Load	20%	20%	20%
15-year Net Electricity (MWh)	**4.71E+06**	**5.95E+06**	**6.33E+06**
Levelized Gross Power (MWe)	44.80	56.64	60.19
Levelized Net Power (MWe)	**35.84**	**45.31**	**48.15**

* Technical recovery until reaching minimum plant inlet conditions and not limited to the 15-year project life.

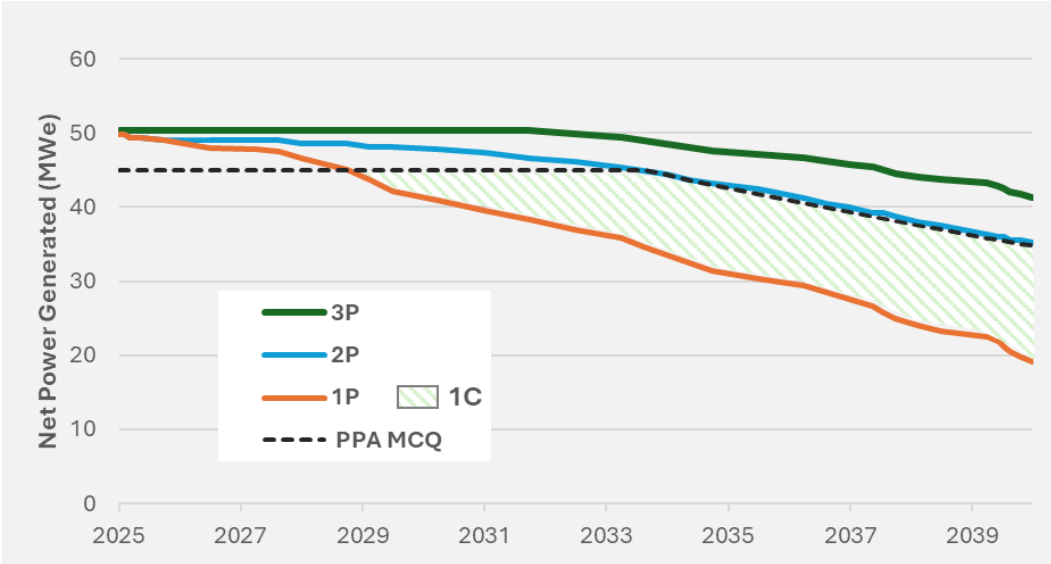


Figure 12: Project B full-field net power generation reserves categories and resources classifications for the 15-year project life. Note that production rates for the ML and high cases are limited by facility constraints during the early years of operation, which then limits their net electricity reserves over the 15-yr project life.

5. DEVELOPMENT STATUS

While class and category are the main designations for quantities of resources, project maturity sub-classes and development statuses provide additional granularity as to the specific status for a project. Recall that Figure 2 is our adaptation of the original chart that is presented in the SPE-PRMS guidelines. Note that within the Reserves class, development statuses begin with Developed and Undeveloped. The Developed status is then divided into Producing and Non-producing, which Non-producing is further sub-divided into Shut-in and Behind Pipe status levels. The SPE-PRMS document also provides definitions for the various status levels, which are reasonably applicable to geothermal resources until such time as an official GRMS document may become available in the industry. Selecting a project maturity sub-class and development status for our Projects A and B is a straight-forward task.

The resources for Project A include quantities in three sub-divisions that describe development or producing status. The developed producing reserves are just as they are named, i.e., quantities from existing wells with completion intervals that are open and actively delivering volumes that result in saleable electricity. The developed shut-in reserves for Project A are those quantities from existing wells with completion intervals that are open but not yet producing because they are waiting on relatively minor expenditures for downhole and/or surface refurbishments. Lastly, the undeveloped reserves are those quantities expected to be recovered through future drilling and completion of the planned pad of horizontal locations. It is important to note that undeveloped reserves are associated with significant capital expenditures and include the expansion of surface power plant facilities.

Table 3: Project B resources classifications, categories, and development statuses.

	Reserves (GWh)			Contingent Resources (GWh)
	1P	2P	3P	1C
Producing	0	0	0	0
Non-producing	944	1,164	1,264	0
Undeveloped	3,765	4,789	5,063	1,120
SUBTOTAL	**4,709**	**5,954**	**6,327**	**1,120**

* All numbers are net electricity sales.

The resources for Project B include development statuses as listed in Table 3. The reserves that are associated with the already drilled and completed wells (i.e., the existing triplet unit) are designated as developed shut-in, since they are simply waiting for surface facilities to be finished and tied into transmission lines. The quantities of reserves that are associated with future drilling of the remaining planned horizontal locations are designated as undeveloped. The 1C contingent resources are sub-classified as *development pending* since they are contingent upon the performance of the already existing and planned wells, and their development status is, of course, undeveloped.

As a thought exercise for illustrative purposes, let us now assume there is another area of interest 25 miles away that is untested, which we will call Project B'. The operator is considering acquiring the acreage, with hopes of leveraging technical, regulatory, and perhaps even operational synergies from the existing Project B that is currently under development. The subsurface lithology and heat model in the new area represent a viable drilling target but involve significant uncertainties (i.e., no well data, fault separated, unknown hydrology, uncertain whether the heat anomaly found in Project B extends to the new Project B' area, etc.). The exploratory nature of Project B' classifies its geothermal resources as prospective, which by definition are undeveloped. Referring back to Figure 2, the sub-class of these resources aligns with *prospect*, due to their relative level of maturity, which is influenced by analysis, assumptions, and operator activities from Project B.

6. CONCLUSION

A conceptual GRMS based on the SPE-PRMS principles for hydrocarbons works well as a classification framework for geothermal resources, as we have demonstrated by its application to multiple example projects. It is recommended as an appropriate standard for general use by the industry. Two projects, including both conventional hydrothermal as well as unconventional EGS operations, and covering a range of development statuses from undeveloped to non-producing to producing, were presented. Both case studies provide examples of how the framework can be successfully applied using familiar terminology and standards that have been time-tested in the petroleum industry. The framework is project based and provides classifications for commercial maturity, categorization based on technical uncertainty, as well as additional sub-classes and development statuses. Together, these key terms provide consistency and transparency of communication for critical project details. Widespread application is expected to aid in investment, portfolio management, and greater development of geothermal energy.

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